KINDER MORGAN

July 30, 2018

Anne L. Idsal, Regional Administrator
US EPA Region 6
Fountain Place
1445 Ross Ave.
Dallas, TX 75202-2750

Re: **Case-by-Case MACT Determination Application**
Single Point Mooring System to Export Crude Oil
Crude Oil Loading Terminal (COLT) Project
Gulf of Mexico

Dear Administrator Idsal:

Kinder Morgan, Inc. is providing this case-by-case maximum achievable control technology ("MACT") determination application to support a Deepwater Port Act ("DPA") authorization for a proposed single-point mooring ("SPM") system used to export crude oil known as the Crude Oil Loading Terminal ("COLT") project, to be located approximately 35 miles offshore from the Gulf coast of Texas. By this application, Kinder Morgan respectfully requests that the U.S. Environmental Protection Agency ("EPA") issue a Notice of MACT Approval ("NOMA") for the COLT project pursuant to 40 C.F.R. Section 40-43.

As provided in the application, a review of the available information related to control technologies as well as the characteristics of the SPM system operation establishes that submerged loading operations represents case-by-case MACT for the COLT project.

If you should have any questions, please contact me at (713) 369-8032.

Sincerely,

Richard Steinberg
Director, EHS

Case-by-Case MACT Determination for:
Single Point Mooring System
Used to Export Crude Oil

KINDER MORGAN

COLT Project
Deep Water Loading Operation
Gulf of Mexico

JULY 2018

Table of Contents

List of Tables

Appendices

Executive Summary

Kinder Morgan, Inc. is providing this case-by-case maximum achievable control technology ("MACT") determination application to support a Deepwater Port Act ("DPA") authorization for a proposed single-point mooring ("SPM") system used to export crude oil known as the Crude Oil Loading Terminal ("COLT") project, to be located approximately 35 miles offshore from the Gulf coast of Texas. Kinder Morgan respectfully requests that the U.S. Environmental Protection Agency ("EPA") issue a Notice of MACT Approval ("NOMA") for the COLT project pursuant to 40 C.F.R. §§ 40-43.

Under the DPA, EPA reviews license applications for certain projects by reference to, among other provisions, relevant "new source" requirements of the federal Clean Air Act ("CAA"). 33 U.S.C. § 1502(9)(D). Under Section 112(g) of the CAA, a case-by-case MACT review is appropriate for a new major source of hazardous air pollutants ("HAPs") for which "no applicable emission limitations have been established by the Administrator." CAA § 112(g)(2)(B). Further, under EPA's Section 112(g) implementing rules, such a review is appropriate "unless the source in question has been specifically regulated or exempted from regulation under a standard issued pursuant to Section 112." 40 C.F.R. § 63.40(b).

COLT is not subject to "applicable emission limitations" under, nor is it "specifically regulated or exempted under" any existing MACT standard promulgated to date by EPA. In 1996, EPA promulgated a regulation for an "offshore loading terminal" source category in MACT Subpart Y (40 C.F.R. §§ 560-568). However, neither MACT Subpart Y nor any other MACT standard established by EPA under Section 112 specifically regulated or exempted, nor established applicable emissions limitations for the COLT project. For reference, the regulatory language and history of MACT Subpart Y is included as Appendix B.

This application was completed in accordance with the specific requirements of 40 CFR Part 63, §§ 63.40 through 63.44. To ensure that all potentially relevant control technologies were identified, several sources of information were evaluated in order to determine MACT, defined in the statute and rule for new sources as:

> [T]he emission limitation which is not less stringent than the emission limitation achieved in practice by the best controlled similar source, and which reflects the maximum degree of reduction in emissions that the permitting authority, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable by the constructed or reconstructed major source."

40 C.F.R. § 63.41. *See also* Clean Air Act § 112(d)(2).

As outlined in the application, a review of the best controlled similar sources and consideration of add-controls confirmed that <u>submerged loading represents MACT for the COLT project</u>. To date, there are no large volume offshore loading terminals with add-on controls, either on board loaded vessels or on adjacent moored barges or workboats.

Section 1
Introduction

1.1 Facility Background

KM proposes to construct and operate an SPM system to facilitate the loading of crude oil to oceangoing crude oil cargo vessels. The SPM system will be able to accommodate a fully laden Very Large Crude Carrier ("VLCC"), one of the 2 million barrel tankers that offer the most efficient shipping to customers in their own vessels. The COLT project does not contemplate a captive fleet.

The SPM system would not involve a stationary berth or dock for loading operations. Instead, vessels would be secured to a buoy by a hawser line running from the bow of the vessel. Once secured, the vessel would be connected to the pipeline by a flexible floating hose of approximately 800 feet in length, delivered by launch to the vessel. The vessel would hoist and connect the flexible hose amidships for loading crude oil from the pipeline. While loading, the vessel would stay in motion around the buoy, so that it can orient itself with changing weather conditions. The single-point mooring design minimizes the risks normally associated with a stationary offshore dock or berth, especially in inclement weather and rough seas.

The SPM system is not itself a significant source of emissions. Rather, volatile organic compounds ("VOC") including Hazardous Air Pollutants ("HAPs") will be emitted by the vessels as a result of vapor displacement during loading operations. Total throughput is projected at 550 million barrels of crude oil per year. Vessel VOC emissions will exceed 250 tons per year and HAP emissions will exceed 25 tons per year. While these emissions will displace similar emissions currently existing as a result of lightering operations, the avoided lightering emissions are not presented here.

KM expects to begin construction in 2020 and complete construction in 2021. The COLT project is expected to being operations in 2021.

1.2 Requirements for a Case-By-Case MACT Determination

KM anticipates that COLT will be reviewed against "new source" requirements of the CAA as part of its DPA license authorization. Accordingly, KM conducted a case-by-case analysis to establish a MACT emission standard because the SPM system is not specifically regulated or exempted from regulation under a standard issued pursuant to CAA §§ 112(d), 112(h), or 112(j).

The requirements for a case-by-case MACT analysis are described in 40 CFR § 63.43(e). Under that section, an application for a MACT determination must specify a control technology selected by the owner or operator that, if properly operated and maintained, will meet the MACT emission limit or standard as proposed by the applicant and approved by the permitting authority according to the principles set forth in 40 CFR § 63.43(d).

For a new source, MACT is defined as the emission limitation which is not less stringent than that achieved in practice by the best controlled similar source and which reflects the maximum degree of reduction in emissions that is achievable by the constructed or reconstructed major source. In accordance with § 63.43(d)(3), the MACT standard may be determined to be a specific design, equipment, work practice, or operational standard, or a combination thereof, if it is not feasible to prescribe or enforce an emission limitation. Table 1 provides a list of the required information for a complete submittal of a case-by-case MACT analysis.

Furthermore, § 63.43(c)(4) requires that KM must comply with all applicable requirements of Subpart A of 40 CFR Part 63 with respect to operation of the SPM system. These MACT general provisions are listed in §§ 63.1 through 63.16.

This application is organized into the following sections:

Section 1 presents the Introduction, MACT Informational Requirements, and Methodology.

Section 2 describes the SPM system operations, which will allow for a better understanding of the MACT floor concept of "similar source." Additionally, this information will provide guidance in determining whether any "beyond-the-floor" control technologies are technically feasible.

Section 3 contains an evaluation of control technologies, equipment design, work practices, and operational standards of similar sources and includes the MACT floor and "beyond the floor" analysis.

Section 4 provides the proposed case-by-case MACT determination and operational standards to demonstrate compliance.

Appendix A contains Case-by-Case MACT Regulations

Appendix B contains MACT Y Regulations and History

Appendix C contains Similar Source Permit Information

Appendix D contains RBLC Search Results

Appendix E contains International Trade Journal Review

1.3 Overview of Case-By-Case MACT Analysis Methodology

Two steps are usually used in order to determine MACT:

1. Identify the “MACT floor:” a control technology that represents the highest control achieved in practice by the best-controlled similar source; and
2. Determine whether ”beyond-the-floor” controls can be achieved in light of cost, non-air quality health and environmental impacts, and energy requirements.

The case-by-case MACT analysis for the SPM system is based on this two-step process.

The determination of similar sources and evaluation of control technology in Section 3 provides the basis for the MACT floor and ”beyond the floor” analysis. It also includes relevant discussion gathered from a RACT/BACT/LAER Clearinghouse (“RBLC”) search, a review of published MACT standards, add-on VOC controls US Coast Guard Rules, International Maritime Organizational and Safety Regulations and relevant international operations.

Table 1

Requirements for a Case-By-Case MACT Determination

Application Requirements	Location of Requirement Content
(i) The name and address of the major source	Introduction; Section 1.1
(ii) A brief description of the major source and identification of any listed source category or categories in which it is included	Facility Background; Section 1.2
(iii) The expected commencement date for the construction	Facility Background; Section 1.2
(iv) The expected completion date for construction	Facility Background; Section 1.2
(v) The anticipated date of start-up	Facility Background; Section 1.2
(vi) The HAP(s) emitted by the source and the estimated emission rate for each such HAP	Emission Calculations; Section 2.3 and Table 2
(vii) Any federally enforceable emission limitations applicable to the constructed major source	NSR Permiting Process
(viii) The maximum and expected utilization of the source and the associated uncontrolled emission rates for that source	Emission Calculations; Section 2.3 and Table 2
(ix) The controlled emissions for the source in tons per year at expected and maximum utilization	Emission Calculations; Section 2.3 and Table 2
(x) A recommended emission limitation for the constructed or reconstructed major source consistent with the principles set forth in §63.43(d)	Emission Calculations; Section 2.3 and Table 2 and Section 4.1
(xi) The selected control technology to meet the recommended MACT emission limitation	Proposed MACT Determination; Section 4.1
(xii) Supporting documentation, including identification of alternative control technologies considered by the applicant to meet the emission limitation	Beyond the Floor Analysis, Section 3.2
(xiii) Any other relevant information required pursuant to 40 CFR 63 Subpart A	See Appendices

Section 2
Source Definition

2.1 Process Description

The Crude Oil Loading Terminal (COLT) project will consist of an SPM system, securing line(s), and a flexible floating hose connected to a submerged pipeline. The operation of the SPM system itself will not result in significant air emissions. However, vessel emissions will be generated from vapor displacement from loading activities.

Crude oil will be delivered to the vessels by subsea pipeline. The loading process begins by securing the bow of the vessel to the buoy via a hawser line. Once secured, the vessel would be connected to the pipeline by a flexible floating hose of approximately 800 feet in length, delivered by launch to the vessel. The vessel would hoist and connect the flexible hose amidships for loading crude oil from the pipeline. While loading, the vessel would stay in motion around the buoy, so that it can orient itself with changing weather conditions. The single-point mooring design minimizes the risks normally associated with a stationary offshore dock or berth, especially in inclement weather and rough seas.

2.2 Air Emissions

The HAP emissions from the vapor displacement into the vessel holds consists of volatile HAPs from crude oil loading. The system's throughput is projected at up to 550 million barrels of crude oil per year at a loading rate up to 85,000 barrels per hour.

2.3 Emission Calculations

The routine loading losses result from total vapors displaced and generated by loading liquids into the marine vessels. The uncontrolled loading losses have been calculated using Equation 1 from AP-42, Section 5.2:

$$L_L = 12.46 \frac{SPM}{T}$$

where:

LL= loading loss, lb/1000 gallons of product loaded.

S = AP 42 saturation factor – the saturation factor of 0.2 is used for submerged loading of ships.

P = True Vapor Pressure at maximum temperature, psia.

M = Molecular weight of crude oil vapor, lb−lbmol

T = Temperature of product loaded, degrees Rankine.

HAP emissions were calculated based on expected ship loading throughput. Detailed emission calculations are included in Table 2. The true vapor pressure and molecular weight of crude oil were based on an expected annual averages for North American Crude. Finally, the HAP concentrations were based on Table A-1 from the 2015 Emissions Estimation Protocol for Petroleum Refineries.

Table 2

Summary of Potential Emissions

Parameter	Units	Value
Ship Saturation Factor	0.2	Dimensionless
True Vapor Pressure of Crude Oil[1]	7.69	psia
Molecular Weight of Vapors[1]	50	lb/lb-mole
Temperature of Vapor	539.67	^{o}R
Total Loading Loss	1.78	lb/10^3 gal
Annual Throughput	550,000,000	bbl/yr

Crude Oil HAP Speciation [2]	
1,3-Butadiene	0.0001%
n-Hexane	1.34%
2,2,4-Trimethyl Pentane	0.19%
Benzene	0.31%
Toluene	0.54%
Xylenes (total)	0.81%
Ethylbenzene	0.19%
Cumene	0.11%
1,2,4-Trimethyl Benzene	0.38%
Naphthalene	0.14%
Biphenyl	0.03%
Total HAP:	**4.03%**

Emission Rates	
Total HAP Emissions from Marine Loading	826.65

Notes:

1.) True vapor pressure and molecular weight based on expected annual average North American crude oil.

2.) HAP concentration based on Table A-1 from the 2015 Emissions Estimation Protocol for Petroleum Refinierie

Section 3
Evaluation of Control Technologies

As described in 40 CFR §§ 63.43(d)(1) and (2) (see Appendix A), MACT emission limitations or requirements determined by an applicant and approved by the permitting authority shall not be less stringent than the emission control which is “achieved in practice by the best controlled similar source.” Additionally, applicants must determine whether stricter controls are achievable.

Regulatory programs such as New Source Review (“NSR”), existing MACT Standards, EPA guidance on control technologies, and International applications were used to conduct a review of emission controls for similar sources as well as to determine whether or not stricter controls are achievable.

A MACT floor analysis was first conducted to determine the level of controls on similar sources. Next, a ”beyond the floor” analysis was performed to determine whether or not stricter controls are achievable. The result of the evaluation determines MACT for the COLT project.

3.1 MACT Floor Analysis

As specified within the principles of MACT determinations, 40 CFR 63.43(d), the MACT requirements shall not be less stringent than the emission control which is achieved in practice by the best controlled “similar source.” Section 63.43 defines a similar source as a stationary source or process that has comparable emissions and is structurally similar in design and capacity to a constructed or reconstructed major source such that the source could be controlled using the same control technology.

As discussed in the subsections below, the MACT floor was determined through a review of nationwide permits for large offshore loading terminals, RACT/BACT/LAER Clearinghouse, and published MACT standards.

3.1.1 Similar Source Permit Search

A nationwide search was conducted in order to identify similar sources. Two large offshore SPM facilities were identified that load or propose to load crude into VLCCs: Limetree Bay Terminals (“Limetree”) in St. Croix, Virgin Islands and the Louisiana Offshore Oil Port (“LOOP”) in the Gulf of

Mexico off the coast of Louisiana. These are the only two sources identified in the permit search as addressing sources "similar" to COLT, as defined in Section 63.43.

Limetree is recently permitted (2018) and under construction to export crude into VLCCs through an SPM system. LOOP is in operation and licensed under the Deepwater Port Act and imports and exports crude through an SPM system. Both facilities use submerged loading to minimize volatile HAP emissions. EPA concurrence on the use of submerged loading for Limetree and LOOP's 2000 amended DPA license is included in Appendix C.

3.1.2 RACT/BACT/LAER Clearinghouse Search

The EPA maintains a database of control technology determinations made throughout the United States. This database represents the largest compendium available in the field of air pollutant source requirements and control capabilities and is a useful resource when conducting a nationwide case-by-case MACT analysis. As part of this nationwide control technology search, therefore, the RACT/BACT/LAER Clearinghouse ("RBLC") database was queried for 'Loading,' 'SPM,' 'Mooring,' 'Buoy,' and 'Offshore' from August 1, 2008 to present (longer than a 5-year period). The only query which returned information for any process was related to the 'Loading' parameter. Each process returned in the query could be from an unrelated industry; therefore, the number of records returned may not be related to SPM systems. A total of 2,868 records were obtained from the 'Loading' query, downloaded into an Access database, and filtered to list only marine loading records. After review of the marine loading records, it is evident that there are no similar sources within the RBLC database. The RBLC results are included in Appendix D.

3.1.3 Published MACT Standards

The EPA has promulgated a variety of control technology standards in recent years for area sources (facilities emitting less than 10 tons per year of any one HAP and less than 25 tons per year total HAPs) and major sources (facilities emitting 10 tons per year or more of any one HAP and 25 tons per year or more total HAPs).

The control technology standards promulgated in 40 CFR Part 63 were reviewed to determine whether any promulgated standard is relevant to COLT. Of the 133 NESHAPs promulgated in Part 63 (Subparts F through 7H), the MACT standard most closely associated with crude oil loading is MACT Y, National Emission Standards for Marine Tank Vessel Loading Operations.

COLT is not subject to “applicable emission limitations” under, nor is it “specifically regulated or exempted under” MACT Subpart Y (40 C.F.R. §§560-568). Neither MACT Subpart Y nor any other MACT standard established by EPA under Section 112 specifically regulated or exempted, nor established applicable emissions limitations for, the COLT project. For reference, the regulatory language and history of MACT Subpart Y is attached as Appendix B.

3.1.4 MACT Floor Determination

Given that both similar sources employ submerged loading and that MACT requirements for the COLT project shall not be less stringent than the best controlled similar source, the MACT floor for the COLT project is submerged loading.

3.2 “Beyond the Floor” Analysis

As discussed in Section 2, the operation of the SPM system itself will not result in significant emissions. However, HAP emissions will be produced from vapor displacement when loading ships. Even though no similar sources use add-on controls, KM evaluated add-on control technologies, and the details of this evaluation are provided below.

Air Pollution Technology Fact Sheets and Technical Bulletins are maintained on the EPA’s Clean Air Technology Center (“CATC”) Products website. The Air Pollution Control Technology Fact Sheets are short descriptions of different types of control technologies, including emission limits and reductions, application, costs, and characteristics. The Technical Bulletins are longer documents with more detailed information about specific control technologies. Various add-on control technologies capable of controlling VOC emissions were identified during the review of the Technical Bulletins and Fact Sheets.

The subsections below summarize VOC control technologies identified in the CATC information in relation to controlling displaced vapors during loading. The VOC control technologies evaluated include:

- Combustion;
- Condensation;
- Adsorption; and
- Absorption.

In addition, the beyond the floor analysis included evaluating whether it is feasible to implement these add-on controls for: (1) Offshore collection and onshore recovery/control and (2) Offshore collection and offshore recovery/control. These options were researched for operations in the United States and internationally. The results were then compared to the large volume crude exporting specifics of the COLT project.

In relation to offshore loading at COLT, there are several factors affecting the technical practicability, economic reasonableness, operational feasibility, and safety concerns of each option and add-on control. These factors are discussed in Subsection 3.2.7 and confirm why to date, there are no large volume offshore loading terminals with add-on controls, either on board loaded vessels or on adjacent moored barges or workboats.

3.2.1 Combustion

Combustion devices typically used to control VOC vapors include: flares, vapor combustion units (incinerators), and catalytic incinerators. Utilizing thermal combustion, the displaced vapor is oxidized to carbon dioxide and water in the presence of oxygen and a fuel source (e.g., natural gas). Vapor combustion units can handle a wide variety of vent gas compositions and achieve destruction efficiencies in excess of 98%. Combustion devices produce products of incomplete combustion including nitrogen oxides (NOx), carbon monoxide (CO), sulfur dioxide (SO2), and particulate matter. The level of destruction efficiency is dependent on operating temperature, residence time, and turbulence (i.e., gas mixing).

3.2.2 Condensation

If the temperature of the displaced vapor is sufficiently reduced, the VOC content will condense, separate from the vapor and a portion recovered. The condensation process is achieved by compressing the outlet gas, removing any water, and then routing the remaining stream through a refrigeration unit to condense and recover the VOC. To achieve higher removal efficiencies (90%), a complex system molecular sieve or methanol injection prior to refrigeration is normally needed.

3.2.3 Adsorption

Adsorption is used to remove VOCs from low to medium concentration gas streams. Adsorption is a process where gas molecules passing through a bed of solid particles are selectively held there by attractive forces that are weaker and less specific than those of chemical bonds. Carbon adsorption systems (CAS) can be used to control displaced vapor depending on the compound to be removed, gas temperature, and concentration. CAS systems typically contain two carbon beds in series that become saturated over time and must be regenerated or recycled for continued use.

3.2.4 Absorption

Absorption is a process where one or more soluble components of a gas mixture are dissolved in a liquid. The liquid used could be crude oil. The displaced vapor is compressed and passed through an absorber column where it is contacted with crude oil into which the VOC components are absorbed. The crude oil containing the absorbed VOCs can then be stored or recycled. Recovery efficiencies vary and the non-recovered VOC are vented to the atmosphere and are dependent on liquid flowrate through the absorber column, column pressure, and crude oil temperature.

Absorption can also be done in two stages near atmospheric pressure. In this process, the VOC vapor is first absorbed in a cold lean oil liquid (e.g., kerosene). The vapors are then stripped out of the lean oil using heat in a regenerative system and then absorbed into crude oil in the second stage absorber. These types of systems have relatively high energy demands requiring both chilling and heat for regeneration.

3.2.5 International Maritime Organization and Safety Review

The International Maritime Organization's ("IMO") MARPOL Annex VI covers Regulations for the Prevention of Air Pollution from Ships. Regulation 15 of MARPOL Annex VI covers vapor emission control systems ("VECS") and VOC emissions from tankers. According to Regulation 15, confirmation that a ship controls VOC emissions using an approved VECS is required for ports or terminals that the U.S. designates as required to regulate VOC emissions from tankers. The United States Coast Guard ("USCG") and EPA are jointly involved in the compliance and enforcement of these regulations. MSC/Circ 585 "Standards for Vapor Emission Control Systems" provides international standards for the design, construction, and operation of vapor control systems for tankers and shore-side terminals. These regulations and standards developed by the IMO are applicable to tankers and shore-side or onshore terminals, and the SPM system does not fall into either of these categories.

Similarly, the International Chamber of Shipping (ICS), the Oil Companies International Marine Forum (OCIMF), and the International Association of Ports and Harbors (IAPH) publishes a guide for the safe operation of tankers and the terminals that serve them. The fifth version of the International Safety Guide for Oil Tankers and Terminals (ISGOTT) was published in 2006 and provides safety guidelines and recommendations for many marine operations including vapor emission control systems and single point mooring systems. The ISGOTT guide provides operational advice to assist personnel directly involved in tanker and terminal operations. It does not provide a definitive description of how tanker and terminal operations are conducted.

Both the IMO Regulations and ISGOTT identify numerous potential safety hazards associated with VECS and measures to alleviate them. These hazards include:

- Fire or explosion due to ignition of flammable vapor/air mixtures;
- Tank rupture caused by overpressure or vacuum;
- Overfilling (which could lead to spillage and consequent marine pollution or to liquid being sent to the vapor treatment equipment);
- Condensate build-up in vapor return line;
- Misconnection of vapor return line to a shore side liquid loading line;
- Inadvertent addition of inert gas to the vapor return system;
- Mixing of cargoes that react with each other leading to evolution of heat or gases leading to tank rupture or explosion;
- Fouling of equipment due to particles from inert gas systems; and
- Fires, explosions or other hazards caused by the effect of hazard conditions in nearby plant or equipment (e.g. a fire in a tank located near a combustion unit).

All of these hazards are relevant to the potential use of add-on control technologies as applied to the COLT project.

3.2.6 International Operations Review

A review of international operations relevant to crude oil loading and SPM systems was conducted in order to provide a broader assessment of control technologies applied in different jurisdictions and environments. The results of the review found existing crude loading operations serving the North Sea oil production to on-shore facilities. Without the availability of subsea pipelines, oil producers transfer their crude oil from oil production platforms using a dedicated fleet of ships.

In order to comply with the emission reduction commitments of the 1991 Geneva Protocol, producers on the Norwegian Continental Shelf (“NCS”) have been regulated by individual permits, and these producers formed the VOC Industry Cooperation (“VOCIC”). In order to meet their permit requirements, companies operating in the NCS developed a specialized fleet of dedicated shuttle tankers to transport crude oil from the production platforms.

The VOCIC established an agreement including more than 20 companies with licenses to extract oil in the NCS called the “VOC Agreements for outfitting of NMVOC Plants on shuttle tankers serving Norwegian Offshore Loading Oilfields.” The VOCIC, under this agreement, coordinates compliance with the permit requirements.

The North Sea VOC emission limitation for crude loading is 0.45 kg/m3 or 157.5 lb/1,000 bbl. In order to achieve the North Sea limit, the members of the VOCIC installed VOC emission reduction systems (condensation systems) on 15 dedicated shuttle tankers. In comparison, this emission limit is twice as high as the 74.6 lb/1000 bbl VOC estimated for the COLT project, which would not require add-on controls in the North Sea.

The consortium-funded shuttle system to transport crude oil using a dedicated fleet of ships is commercially and operationally distinct from the crude export terminal-for-hire proposed in the COLT project. The North Sea operations are controlled by a defined group of companies who own their crude and control their own shipping, whereas the COLT SPM system would be employed by independent customers. In a terminal-for-hire, the terminal owner/operator neither owns the crude nor controls the shipping.

KM estimates that up to 30 different VLCC tankers would be needed to meet the market demands of the COLT project given the logistics transporting the crude from the Gulf Coast to overseas customers. These VLCC tankers are not currently configured to employ add-on controls, KM has no means to impose the cost to retrofit 30 vessels with add-on controls as part of the COLT project. Such a requirement would make the project infeasible and cost-prohibitive. Finally, the energy requirements associated with the project are inconsistent with this shuttle tanker approach.

The VOC technologies and international operations review are used to determine the beyond the floor determination for the COLT project. Subsection 3.2.7 discusses the factors affecting the technical practicability, economic reasonableness, operational feasibility, and safety concerns associated with each option and add-on control.

3.2.7 “Beyond the Floor” Determination

The beyond the floor analysis included evaluating whether it is feasible to implement these add-on controls for: (1) Offshore collection and onshore recovery/control and (2) Offshore collection and offshore recovery/control. These options were researched for operations in the United States and internationally. The results were then compared to the large volume crude exporting specifics of the

COLT project and whether ”beyond-the-floor” controls can be achieved in light of cost, non-air quality health and environmental impacts, and energy requirements. A literature review was conducted to evaluate the options. Associated information is included in Appendix F.

1. Offshore collection and onshore recovery/control

Although it is common to control VOC emissions from loading operations at on-shore terminals, there are typically no facilities for collecting and controlling vapors at off-shore loading terminals. Petroleum Technology Quarterly Q4 2016 (VOC Recovery in crude oil loading) included in Appendix E offers the following factors that impact the feasibility of offshore collection to onshore recovery and control:

- Excessive distance to shore for sub-sea pipelines (35 miles). The associated cost of adding an additional vapor return subsea pipeline to shore is prohibitive.
- Difficulty in providing offshore compression of the vapor to be sent back to shore. There are limitations of location, space and power requirements operating offshore; and
- The potential for liquid drop-out in vapor return lines and operational impacts such as slugging.

The article concluded that “transporting the vapor onshore by pipeline was impractical, and a full offshore solution would be required.” For these reasons, offshore collection to onshore recovery and control was deemed infeasible. For the same reasons, KM determined that it would be infeasible to transport vapor for processing either onshore or to a platform located in the vicinity of the SPM system. KM identified no operationally sound and safe means of providing compression or of managing liquid drop-out and slugging in a vapor return line of sufficient distance to avoid impeding SPM system operation.

2. Offshore collection and offshore recovery/control.

Offshore collection and offshore recovery/control was then evaluated for consideration of beyond the floor determination. A literature review was used to determine the feasibility of included the above described add-on controls offshore.

Petroleum Technology Quarterly Q4 2016 (VOC Recovery in crude oil loading)) offers the following general factors that impact the feasibility of offshore collection and recovery/control:

a. Lack of readily available utilities including power needed especially for condensation;

b. Normally unattended facilities. Although the COLT project anticipates personnel responsible for the loading operation, there would not normally be qualified staff present to oversee the VECS as in an onshore terminal;
c. Complex combinations of wind, current, and swell affecting the position of the ship, and any moored barges or workboat;
d. Cost sensitivity to weight and footprint of the installed control equipment; and
e. Complexity to design for highly saline environment.

The article points out that "locating equipment on a modified SPM buoy or on a towing tug was considered infeasible due to a lack of deck space."

To support the conclusion that a moored barge is not feasible for add-on controls for the COLT project, a 2014 Japanese study was found that involved a custom-made barge to be moored alongside tankers. The barge contained an absorber tower to remove crude oil vapors.

The article "Vapor Recovery Technique for Crude Oil Ship Loading – Spray Absorption" Japan Future Enterprise Technical Report No. 19, March 2014 included in Appendix E provides a review of a tanker vapor recovery ("TVR") system that might theoretically be utilized for the reduction of VOC emissions generated from crude oil ship loading. The JFE report concluded that it is not possible to "secure a site for installation of a TVR plant" at an SPM buoy due to the unavoidable swaying caused by the waves which interfered with the performance of the absorber tower. In fact, the article states that "As a result, the absorbent will not properly utilize the surface area necessary for absorption in the absorber tower." The article notes that a system that uses a packed absorber tower is in not in use in any of the developed deep-water oil fields or floating production, storage, and offloading (FPSO) systems. Similarly, KM identified no operationally sound and safe technology that would support an add-on control system located on an adjacent barge or ship.

The results of the "beyond the floor" analysis conclude that that no additional controls beyond submerged loading could represent MACT for the COLT project. For many of the operability, safety, cost and energy considerations outlined above, KM identified no large -volume offshore loading SPM systems with add-on controls, either on board loaded vessels, on platforms, or on adjacent moored barges or workboats.

Section 4
Case-By-Case MACT Determination

4.1 Identified Control Technologies, Equipment Design, Work Practices, and Operational Standards

The MACT floor for new sources are set based on the emission limitation achieved in practice by the best controlled similar source. "Similar source" is defined as "a stationary source or process that has comparable emissions and is **structurally similar in design and capacity** to a constructed or reconstructed major source such that the source could be controlled using the same control technology." 40 C.F.R. § 63.41 (emphasis added).

The preamble to the rule implementing Section 112(g) of the Clean Air Act notes that when determining if sources are similar, EPA may consider "the volume and concentration of emissions, the type of emissions, the similarity of emission points, and the cost and effectiveness of controls for one source category relative to the cost and effectiveness of those controls for the other source category, **as well as other operating conditions.**" The costs that EPA considers when determining if two sources are similar "include[s] the purchase price of controls plus the costs associated with installation and operation of those controls for the source in question." *Id.* at 68395.

Subsection 3.2.7 discusses the factors affecting the technical practicability, economic reasonableness, operational feasibility, and safety concerns of each option and add-on control.

While some control systems were identified on facilities such as shuttle tankers and onshore terminals, this review found no comparable SPM systems in which controls were installed. In comparison to oil production platform support systems with dedicated shuttle tankers, comparable vessels are not available on the market that COLT will serve.

Beyond-the-Floor Standards for New Sources

After setting a MACT floor, EPA may impose stricter "beyond-the-floor" limits if it determines that stricter limits are achievable after "taking into consideration the cost . . . and any non-air quality health and environmental impacts and energy requirements." *Sierra Club v. EPA*, 353 F.3d 976, 980 (D.C. Cir. 2004) (citing CAA Section 112(d)(2), 42 U.S.C. 7412(d)(2)). In setting beyond-the-floor standards, EPA looks to what is feasible. *Id.* For example, in *Sierra Club v. EPA*, the D.C. Circuit found that EPA had "reasonably refused" to set beyond-the-floor standards for copper smelters because EPA had determined that "there are no commercial-scale pretreatment processes available" that would have made the Sierra Club's proposed beyond-the-floor control technology predictable and consistent. *Id.*

As with the proposed beyond-the-floor control technology in *Sierra Club*, there are no control technologies that would make stricter beyond-the-floor limits feasible for COLT. Add-on control technologies are not commercially available, and are not achievable for the COLT project due to safety, operational feasibility, engineering and cost, and there are no other available processes that would make stricter emissions limits for the single-point mooring system achievable. Neither a dedicated tanker fleet, nor any of the other add-on control options surveyed by KM are consistent with the energy requirements that the project will serve.

4.2 Proposed MACT Determination

Pursuant to 40 CFR § 63.43(e), an application for a MACT determination must specify a control technology that, if properly operated and maintained, will meet the MACT emission limitation or standard as determined according to the principles set forth in paragraph (d) of that section.

As demonstrated in this application, submerged loading is an accepted control method for SPM system crude oil loading and unloading operations. In accordance with 40 CFR § 63.43(e), KM determined that submerged loading for VOC emission control represents MACT for the COLT project.

4.3 Operational, Monitoring, Recordkeeping Measures

The following operational measures are proposed to demonstrate continuous compliance with the equipment/operational emission limitation identified above. These proposed MACT standards include operation, monitoring, and recordkeeping requirements for the SPM system.

1. All loading shall be submerged and rolling 12-month throughput records shall be updated on a monthly basis for each product loaded.
2. Submit an initial notification. The notification shall be submitted not later than 365 days after the effective date of the emissions standards and shall provide the following information:
   a. The name and address of the owner or operator;
   b. The address (i.e., physical location) of the source;

c. An identification of this emissions standard that is the basis of the notification and the source's compliance date;

d. A brief description of the nature, size, design, and method of operation of the source;

e. A statement that the source is a major source.

3. Emission estimation reporting and recordkeeping procedures.

f. Maintain records of all measurements, calculations, and other documentation.

g. Keep readily accessible records of the emission estimation calculations performed for 5 years. Retain records of the emissions estimates determined and records of their actual throughputs for 5 years.

Appendix A

Case-By Case MACT Regulations

such source is operated under the close supervision of technically trained personnel and is not engaged in the manufacture of products for commercial sale in commerce, except in a de minimis manner.

(8) Boat manufacturing

When establishing emissions standards for styrene, the Administrator shall list boat manufacturing as a separate subcategory unless the Administrator finds that such listing would be inconsistent with the goals and requirements of this chapter.

(9) Deletions from the list

(A) Where the sole reason for the inclusion of a source category on the list required under this subsection is the emission of a unique chemical substance, the Administrator shall delete the source category from the list if it is appropriate because of action taken under either subparagraphs (C) or (D) of subsection (b)(3) of this section.

(B) The Administrator may delete any source category from the list under this subsection, on petition of any person or on the Administrator's own motion, whenever the Administrator makes the following determination or determinations, as applicable:

(i) In the case of hazardous air pollutants emitted by sources in the category that may result in cancer in humans, a determination that no source in the category (or group of sources in the case of area sources) emits such hazardous air pollutants in quantities which may cause a lifetime risk of cancer greater than one in one million to the individual in the population who is most exposed to emissions of such pollutants from the source (or group of sources in the case of area sources).

(ii) In the case of hazardous air pollutants that may result in adverse health effects in humans other than cancer or adverse environmental effects, a determination that emissions from no source in the category or subcategory concerned (or group of sources in the case of area sources) exceed a level which is adequate to protect public health with an ample margin of safety and no adverse environmental effect will result from emissions from any source (or from a group of sources in the case of area sources).

The Administrator shall grant or deny a petition under this paragraph within 1 year after the petition is filed.

(d) Emission standards

(1) In general

The Administrator shall promulgate regulations establishing emission standards for each category or subcategory of major sources and area sources of hazardous air pollutants listed for regulation pursuant to subsection (c) of this section in accordance with the schedules provided in subsections (c) and (e) of this section. The Administrator may distinguish among classes, types, and sizes of sources within a category or subcategory in establishing such standards except that, there shall be no delay in the compliance date for any standard applicable to any source under subsection (i) of this section as the result of the authority provided by this sentence.

(2) Standards and methods

Emissions standards promulgated under this subsection and applicable to new or existing sources of hazardous air pollutants shall require the maximum degree of reduction in emissions of the hazardous air pollutants subject to this section (including a prohibition on such emissions, where achievable) that the Administrator, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable for new or existing sources in the category or subcategory to which such emission standard applies, through application of measures, processes, methods, systems or techniques including, but not limited to, measures which—

(A) reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications,

(B) enclose systems or processes to eliminate emissions,

(C) collect, capture or treat such pollutants when released from a process, stack, storage or fugitive emissions point,

(D) are design, equipment, work practice, or operational standards (including requirements for operator training or certification) as provided in subsection (h) of this section, or

(E) are a combination of the above.

None of the measures described in subparagraphs (A) through (D) shall, consistent with the provisions of section 7414(c) of this title, in any way compromise any United States patent or United States trademark right, or any confidential business information, or any trade secret or any other intellectual property right.

(3) New and existing sources

The maximum degree of reduction in emissions that is deemed achievable for new sources in a category or subcategory shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined by the Administrator. Emission standards promulgated under this subsection for existing sources in a category or subcategory may be less stringent than standards for new sources in the same category or subcategory but shall not be less stringent, and may be more stringent than—

(A) the average emission limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has emissions information), excluding those sources that have, within 18 months before the emission standard is proposed or within 30 months before such standard is promulgated, whichever is later, first achieved a level of emission rate or emission reduction which complies, or would comply if the source is not subject to such standard, with the lowest achievable emission rate (as defined by section 7501 of this title) applicable to the source category and prevailing at the time, in the category or subcategory for categories and subcategories with 30 or more sources, or

(B) the average emission limitation achieved by the best performing 5 sources (for which the Administrator has or could reasonably obtain emissions information) in the category or subcategory for categories or subcategories with fewer than 30 sources.

(4) Health threshold

With respect to pollutants for which a health threshold has been established, the Administrator may consider such threshold level, with an ample margin of safety, when establishing emission standards under this subsection.

(5) Alternative standard for area sources

With respect only to categories and subcategories of area sources listed pursuant to subsection (c) of this section, the Administrator may, in lieu of the authorities provided in paragraph (2) and subsection (f) of this section, elect to promulgate standards or requirements applicable to sources in such categories or subcategories which provide for the use of generally available control technologies or management practices by such sources to reduce emissions of hazardous air pollutants.

(6) Review and revision

The Administrator shall review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards promulgated under this section no less often than every 8 years.

(7) Other requirements preserved

No emission standard or other requirement promulgated under this section shall be interpreted, construed or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established pursuant to section 7411 of this title, part C or D, or other authority of this chapter or a standard issued under State authority.

(8) Coke ovens

(A) Not later than December 31, 1992, the Administrator shall promulgate regulations establishing emission standards under paragraphs (2) and (3) of this subsection for coke oven batteries. In establishing such standards, the Administrator shall evaluate—

(i) the use of sodium silicate (or equivalent) luting compounds to prevent door leaks, and other operating practices and technologies for their effectiveness in reducing coke oven emissions, and their suitability for use on new and existing coke oven batteries, taking into account costs and reasonable commercial door warranties; and

(ii) as a basis for emission standards under this subsection for new coke oven batteries that begin construction after the date of proposal of such standards, the Jewell design Thompson non-recovery coke oven batteries and other non-recovery coke oven technologies, and other appropriate emission control and coke production technologies, as to their effectiveness in reducing coke oven emissions and their capability for production of steel quality coke.

Such regulations shall require at a minimum that coke oven batteries will not exceed 8 per centum leaking doors, 1 per centum leaking lids, 5 per centum leaking offtakes, and 16 seconds visible emissions per charge, with no exclusion for emissions during the period after the closing of self-sealing oven doors. Notwithstanding subsection (i) of this section, the compliance date for such emission standards for existing coke oven batteries shall be December 31, 1995.

(B) The Administrator shall promulgate work practice regulations under this subsection for coke oven batteries requiring, as appropriate—

(i) the use of sodium silicate (or equivalent) luting compounds, if the Administrator determines that use of sodium silicate is an effective means of emissions control and is achievable, taking into account costs and reasonable commercial warranties for doors and related equipment; and

(ii) door and jam cleaning practices.

Notwithstanding subsection (i) of this section, the compliance date for such work practice regulations for coke oven batteries shall be not later than the date 3 years after November 15, 1990.

(C) For coke oven batteries electing to qualify for an extension of the compliance date for standards promulgated under subsection (f) of this section in accordance with subsection (i)(8) of this section, the emission standards under this subsection for coke oven batteries shall require that coke oven batteries not exceed 8 per centum leaking doors, 1 per centum leaking lids, 5 per centum leaking offtakes, and 16 seconds visible emissions per charge, with no exclusion for emissions during the period after the closing of self-sealing doors. Notwithstanding subsection (i) of this section, the compliance date for such emission standards for existing coke oven batteries seeking an extension shall be not later than the date 3 years after November 15, 1990.

(9) Sources licensed by the Nuclear Regulatory Commission

No standard for radionuclide emissions from any category or subcategory of facilities licensed by the Nuclear Regulatory Commission (or an Agreement State) is required to be promulgated under this section if the Administrator determines, by rule, and after consultation with the Nuclear Regulatory Commission, that the regulatory program established by the Nuclear Regulatory Commission pursuant to the Atomic Energy Act [42 U.S.C. 2011 et seq.] for such category or subcategory provides an ample margin of safety to protect the public health. Nothing in this subsection shall preclude or deny the right of any State or political subdivision thereof to adopt or enforce

Subpart B—Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act Sections, Sections 112(g) and 112(j)

SOURCE: 59 FR 26449, May 20, 1994, unless otherwise noted.

Back to Top

§63.40 Applicability of §§63.40 through 63.44.

(a) *Applicability.* The requirements of §§63.40 through 63.44 of this subpart carry out section 112(g)(2)(B) of the 1990 Amendments.

(b) *Overall requirements.* The requirements of §§63.40 through 63.44 of this subpart apply to any owner or operator who constructs or reconstructs a major source of hazardous air pollutants after the effective date of section 112(g)(2)(B) (as defined in §63.41) and the effective date of a title V permit program in the State or local jurisdiction in which the major source is (or would be) located unless the major source in question has been specifically regulated or exempted from regulation under a standard issued pursuant to section 112(d), section 112(h), or section 112(j) and incorporated in another subpart of part 63, or the owner or operator of such major source has received all necessary air quality permits for such construction or reconstruction project before the effective date of section 112(g)(2)(B).

(c) *Exclusion for electric utility steam generating units.* The requirements of this subpart do not apply to electric utility steam generating units unless and until such time as these units are added to the source category list pursuant to section 112(c)(5) of the Act.

(d) *Relationship to State and local requirements.* Nothing in this subpart shall prevent a State or local agency from imposing more stringent requirements than those contained in this subpart.

(e) *Exclusion for stationary sources in deleted source categories.* The requirements of this subpart do not apply to stationary sources that are within a source category that has been deleted from the source category list pursuant to section 112(c)(9) of the Act.

(f) *Exclusion for research and development activities.* The requirements of this subpart do not apply to research and development activities, as defined in §63.41.

[61 FR 68399, Dec. 27, 1996]

Back to Top

§63.41 Definitions.

Terms used in this subpart that are not defined in this section have the meaning given to them in the Act and in subpart A.

Affected source means the stationary source or group of stationary sources which, when fabricated (on site), erected, or installed meets the definition of "construct a major source" or the definition of "reconstruct a major source" contained in this section.

Affected States are all States:

(1) Whose air quality may be affected and that are contiguous to the State in which a MACT determination is made in accordance with this subpart; or

(2) Whose air quality may be affected and that are within 50 miles of the major source for which a MACT determination is made in accordance with this subpart.

Available information means, for purposes of identifying control technology options for the affected source, information contained in the following information sources as of the date of approval of the MACT determination by the permitting authority:

(1) A relevant proposed regulation, including all supporting information;

(2) Background information documents for a draft or proposed regulation;

(3) Data and information available for the Control Technology Center developed pursuant to section 113 of the Act;

(4) Data and information contained in the Aerometric Informational Retrieval System including information in the MACT data base;

(5) Any additional information that can be expeditiously provided by the Administrator; and

(6) For the purpose of determinations by the permitting authority, any additional information provided by the applicant or others, and any additional information considered available by the permitting authority.

Construct a major source means:

(1) To fabricate, erect, or install at any greenfield site a stationary source or group of stationary sources which is located within a contiguous area and under common control and which emits or has the potential to emit 10 tons per year of any HAP's or 25 tons per year of any combination of HAP, or

(2) To fabricate, erect, or install at any developed site a new process or production unit which in and of itself emits or has the potential to emit 10 tons per year of any HAP or 25 tons per year of any combination of HAP, unless the process or production unit satisfies criteria in paragraphs (2) (i) through (vi) of this definition.

(i) All HAP emitted by the process or production unit that would otherwise be controlled under the requirements of this subpart will be controlled by emission control equipment which was previously installed at the same site as the process or production unit;

(ii) (A) The permitting authority has determined within a period of 5 years prior to the fabrication, erection, or installation of the process or production unit that the existing emission control equipment represented best available control technology (BACT), lowest achievable emission rate (LAER) under 40 CFR part 51 or 52, toxics—best available control technology (T-BACT), or MACT based on State air toxic rules for the category of pollutants which includes those HAP's to be emitted by the process or production unit; or

(B) The permitting authority determines that the control of HAP emissions provided by the existing equipment will be equivalent to that level of control currently achieved by other well-controlled similar sources (i.e., equivalent to the level of control that would be provided by a current BACT, LAER, T-BACT, or State air toxic rule MACT determination);

(iii) The permitting authority determines that the percent control efficiency for emissions of HAP from all sources to be controlled by the existing control equipment will be equivalent to the percent control efficiency provided by the control equipment prior to the inclusion of the new process or production unit;

(iv) The permitting authority has provided notice and an opportunity for public comment concerning its determination that criteria in paragraphs (2)(i), (2)(ii), and (2)(iii) of this definition apply and concerning the continued adequacy of any prior LAER, BATC, T-BACT, or State air toxic rule MACT determination;

(v) If any commenter has asserted that a prior LAER, BACT, T-BACT, or State air toxic rule MACT determination is no longer adequate, the permitting authority has determined that the level of control required by that prior determination remains adequate; and

(vi) Any emission limitations, work practice requirements, or other terms and conditions upon which the above determinations by the permitting authority are applicable requirements under section 504(a) and either have been incorporated into any existing title V permit for the affected facility or will be incorporated into such permit upon issuance.

Control technology means measures, processes, methods, systems, or techniques to limit the emission of hazardous air pollutants through process changes, substitution of materials or other modifications;

(1) Reduce the quantity of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications;

(2) Enclose systems or processes to eliminate emissions;

(3) Collect, capture or treat such pollutants when released from a process, stack, storage or fugitive emissions point;

(4) Are design, equipment, work practice, or operational standards (including requirements for operator training or certification) as provided in 42 U.S.C. 7412(h); or

(5) Are a combination of paragraphs (1) through (4) of this definition.

Effective date of section 112(g)(2)(B) in a State or local jurisdiction means the effective date specified by the permitting authority at the time the permitting authority adopts a program to implement section 112(g) with respect to construction or reconstruction or major sources of HAP, or June 29, 1998 whichever is earlier.

Electric utility steam generating unit means any fossil fuel fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A unit that co-generates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electric output to any utility power distribution system for sale shall be considered an electric utility steam generating unit.

Greenfield suite means a contiguous area under common control that is an undeveloped site.

List of Source Categories means the Source Category List required by section 112(c) of the Act.

Maximum achievable control technology (MACT) emission limitation for new sources means the emission limitation which is not less stringent that the emission limitation achieved in practice by the best controlled similar source, and which reflects the maximum degree of deduction in emissions that the permitting authority, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable by the constructed or reconstructed major source.

Notice of MACT Approval means a document issued by a permitting authority containing all federally enforceable conditions necessary to enforce the application and operation of MACT or other control technologies such that the MACT emission limitation is met.

Permitting authority means the permitting authority as defined in part 70 or 71 of this chapter.

Process or production unit means any collection of structures and/or equipment, that processes assembles, applies, or otherwise uses material inputs to produce or store an intermediate or final product. A single facility may contain more than one process or production unit.

Reconstruct a major source means the replacement of components at an existing process or production unit that in and of itself emits or has that potential to emit 10 tons per year of any HAP or 25 tons per year of any combination of HAP, whenever:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable process or production unit; and

(2) It is technically and economically feasible for the reconstructed major source to meet the applicable maximum achievable control technology emission limitation for new sources established under this subpart.

Research and development activities means activities conducted at a research or laboratory facility whose primary purpose is to conduct research and development into new processes and products, where such source is operated under the close supervision of technically trained personnel and is not engaged in the manufacture of products for sale or exchange for commercial profit, except in a *de minimis* manner.

Similar source means a stationary source or process that has comparable emissions and is structurally similar in design and capacity to a constructed or reconstructed major source such that the source could be controlled using the same control technology.

[61 FR 68399, Dec. 27, 1996]

Back to Top

§63.42 Program requirements governing construction or reconstruction of major sources.

(a) *Adoption of program.* Each permitting authority shall review its existing programs, procedures, and criteria for preconstruction review for conformity to the requirements established by §§63.40 through 63.44, shall make any additions and revisions to its existing programs, procedures, and criteria that the permitting authority deems necessary to properly effectuate §§63.40 through 63.44, and shall adopt a program to implement section 112(g) with respect to construction or reconstruction of major sources of HAP. As part of the adoption by the permitting authority of a program to implement section 112(g) with respect to construction or reconstruction of major sources of HAP, the chief executive officer of the permitting authority shall certify that the program satisfies all applicable requirements established by §§63.40 through 63.44, and shall specify an effective date for that program which is not later than June 29, 1998. Prior to the specified effective date, the permitting authority shall publish a notice stating that the permitting authority has adopted a program to implement section 112(g) with respect to construction or reconstruction of major sources of HAP and stating the effective date, and shall provide a written description of the program to the Administrator through the appropriate EPA Regional Office. Nothing in this section shall be construed either:

(1) To require that any owner or operator of a stationary source comply with any requirement adopted by the permitting authority which is not intended to implement section 112(g) with respect to construction or reconstruction of major sources of HAP; or

(2) To preclude the permitting authority from enforcing any requirements not intended to implement section 112(g) with respect to construction or reconstruction of major sources of HAP under any other provision of applicable law.

(b) *Failure to adopt program.* In the event that the permitting authority fails to adopt a program to implement section 112(g) with respect to construction or reconstruction of major sources of HAP with an effective date on or before June 29, 1998, and the permitting authority concludes that it is able to make case-by-case MACT determinations which conform to the provisions of §63.43 in the absence of such a program, the permitting authority may elect to make such determinations. However, in those instances where the permitting authority elects to make case-by-case MACT determinations in the absence of a program to implement section 112(g) with respect to construction or reconstruction of major sources of HAP, no such case-by-case MACT determination shall take effect until after it has been submitted by the permitting authority in writing to the appropriate EPA Regional Adminstrator and the EPA Regional Administrator has concurred in writing that the case-by-case MACT determination by the permitting authority is in conformity with all requirements established by §§63.40 through 63.44. In the event that the permitting authority fails to adopt a program to implement section 112(g) with respect to construction or reconstruction of major sources of HAP with an effective date on or before June 29, 1998, and the permitting authority concludes that it is unable to make case-by-case MACT determinations in the absence of such a program, the permitting authority may request that the EPA Regional Administrator implement a transitional program to implement section 112(g) with respect to construction or reconstruction of major sources of HAP in the affected State of local jurisdiction while the permitting authority completes development and adoption of a section 112(g) program. Any such transitional section 112(g) program implemented by the EPA Regional Administrator shall conform to all requirements established by §§63.40 through 63.44, and shall remain in effect for no more than 30 months. Continued failure by the permitting authority to adopt a program to implement section 112(g) with respect to construction or reconstruction of major sources of HAP shall be construed as a failure by the permitting authority to adequately administer and enforce its title V permitting program and shall constitute cause by EPA to apply the sanctions and remedies set forth in the Clean Air Act section 502(I).

(c) *Prohibition.* After the effective date of section 112(g)(2)(B) (as defined in §63.41) in a State or local jurisdiction and the effective date of the title V permit program applicable to that State or local jurisdiction, no person may begin actual construction or reconstruction of a major source of HAP in such State or local jurisdiction unless:

(1) The major source in question has been specifically regulated or exempted from regulation under a standard issued pursuant to section 112(d), section 112(h) or section 112(j) in part 63, and the owner and operator has fully complied with all procedures and requirements for preconstruction review established by that standard, including any applicable requirements set forth in subpart A of this part 63; or

(2) The permitting authority has made a final and effective case-by-case determination pursuant to the provisions of §63.43 such that emissions from the constructed or reconstructed major source will be controlled to a level no less stringent than the maximum achievable control technology emission limitation for new sources.

[61 FR 68400, Dec. 27, 1996, as amended at 64 FR 35032, June 30, 1999]

Back to Top

§63.43 Maximum achievable control technology (MACT) determinations for constructed and reconstructed major sources.

(a) *Applicability.* The requirements of this section apply to an owner or operator who constructs or reconstructs a major source of HAP subject to a case-by-case determination of maximum achievable control technology pursuant to §63.42(c).

(b) *Requirements for constructed and reconstructed major sources.* When a case-by-case determination of MACT is required by §63.42(c), the owner and operator shall obtain from the permitting authority an approved MACT determination according to one of the review options contained in paragraph (c) of this section.

(c) *Review options.* (1) When the permitting authority requires the owner or operator to obtain, or revise, a permit issued pursuant to title V of the Act before construction or reconstruction of the major source, or when the permitting authority allows the owner or operator at its discretion to obtain or revise such a permit before construction or reconstruction, and the owner or operator elects that option, the owner or operator shall follow the administrative procedures in the program approved under title V of the Act (or in other regulations issued pursuant to title V of the Act, where applicable).

(2) When an owner or operator is not required to obtain or revise a title V permit (or other permit issued pursuant to title V of the Act) before construction or reconstruction, the owner or operator (unless the owner or operator voluntarily follows the process to obtain a title V permit) shall either, at the discretion of the permitting authority:

(i) Apply for and obtain a Notice of MACT Approval according to the procedures outlined in paragraphs (f) through (h) of this section; or

(ii) Apply for a MACT determination under any other administrative procedures for preconstruction review and approval established by the permitting authority for a State or local jurisdiction which provide for public participation in the determination, and ensure that no person may begin actual construction or reconstruction of a major source in that State or local jurisdiction unless the permitting authority determines that the MACT emission limitation for new sources will be met.

(3) When applying for a permit pursuant to title V of the Act, an owner or operator may request approval of case-by-case MACT determinations for alternative operating scenarios. Approval of such determinations satisfies the requirements of section 112(g) of each such scenario.

(4) Regardless of the review process, the MACT emission limitation and requirements established shall be effective as required by paragraph (j) of this section, consistent with the principles established in paragraph (d) of this section, and supported by the information listed in paragraph (e) of this section. The owner or operator shall comply with the requirements in paragraphs (k) and (l) of this section, and with all applicable requirements in subpart A of this part.

(d) *Principles of MACT determinations.* The following general principles shall govern preparation by the owner or operator of each permit application or other application requiring a case-by-case MACT determination concerning construction or reconstruction of a major source, and all subsequent review of and actions taken concerning such an application by the permitting authority:

(1) The MACT emission limitation or MACT requirements recommended by the applicant and approved by the permitting authority shall not be less stringent than the emission control which is achieved in practice by the best controlled similar source, as determined by the permitting authority.

(2) Based upon available information, as defined in this subpart, the MACT emission limitation and control technology (including any requirements under paragraph (d)(3) of this section) recommended by the applicant and approved by the permitting authority shall achieve the maximum degree of reduction in emissions of HAP which can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the costs of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction.

(3) The applicant may recommend a specific design, equipment, work practice, or operational standard, or a combination thereof, and the permitting authority may approve such a standard if the permitting authority specifically determines that it is not feasible to prescribe or enforce an emission limitation under the criteria set forth in section 112(h)(2) of the Act.

(4) If the Administrator has either proposed a relevant emission standard pursuant to section 112(d) or section 112(h) of the Act or adopted a presumptive MACT determination for the source category which includes the constructed or reconstructed major source, then the MACT requirements applied to the constructed or reconstructed major source shall have considered those MACT emission limitations and requirements of the proposed standard or presumptive MACT determination.

(e) *Application requirements for a case-by-case MACT determination.* (1) An application for a MACT determination (whether a permit application under title V of the Act, an application for a Notice of MACT Approval, or other document specified by the permitting authority under paragraph (c)(2)(ii) of this section) shall specify a control technology selected by the owner or operator that, if properly operated and maintained, will meet the MACT emission limitation or standard as determined according to the principles set forth in paragraph (d) of this section.

(2) In each instance where a constructed or reconstructed major source would require additional control technology or a change in control technology, the application for a MACT determination shall contain the following information:

(i) The name and address (physical location) of the major source to be constructed or reconstructed;

(ii) A brief description of the major source to be constructed or reconstructed and identification of any listed source category or categories in which it is included;

(iii) The expected commencement date for the construction or reconstruction of the major source;

(iv) The expected completion date for construction or reconstruction of the major source;

(v) the anticipated date of start-up for the constructed or reconstructed major source;

(vi) The HAP emitted by the constructed or reconstructed major source, and the estimated emission rate for each such HAP, to the extent this information is needed by the permitting authority to determine MACT;

(vii) Any federally enforceable emission limitations applicable to the constructed or reconstructed major source;

(viii) The maximum and expected utilization of capacity of the constructed or reconstructed major source, and the associated uncontrolled emission rates for that source, to the extent this information is needed by the permitting authority to determine MACT;

(ix) The controlled emissions for the constructed or reconstructed major source in tons/yr at expected and maximum utilization of capacity, to the extent this information is needed by the permitting authority to determine MACT;

(x) A recommended emission limitation for the constructed or reconstructed major source consistent with the principles set forth in paragraph (d) of this section;

(xi) The selected control technology to meet the recommended MACT emission limitation, including technical information on the design, operation, size, estimated control efficiency of the control technology (and the manufacturer's name, address, telephone number, and relevant specifications and drawings, if requested by the permitting authority);

(xii) Supporting documentation including identification of alternative control technologies considered by the applicant to meet the emission limitation, and analysis of cost and non-air quality health environmental impacts or energy requirements for the selected control technology; and

(xiii) Any other relevant information required pursuant to subpart A.

(3) In each instance where the owner or operator contends that a constructed or reconstructed major source will be in compliance, upon startup, with case-by-case MACT under this subpart without a change in control technology, the application for a MACT determination shall contain the following information:

(i) The information described in paragraphs (e)(2)(i) through (e)(2)(x) of this section; and

(ii) Documentation of the control technology in place.

(f) *Administrative procedures for review of the Notice of MACT Approval.* (1) The permitting authority will notify the owner or operator in writing, within 45 days from the date the application is first received, as to whether the application for a MACT determination is complete or whether additional information is required.

(2) The permitting authority will initially approve the recommended MACT emission limitation and other terms set forth in the application, or the permitting authority will notify the owner or operator in writing of its intent to disapprove the application, within 30 calendar days after the owner or operator is notified in writing that the application is complete.

(3) The owner or operator may present, in writing, within 60 calendar days after receipt of notice of the permitting authority's intent to disapprove the application, additional information or arguments pertaining to, or amendments to, the application for consideration by the permitting authority before it decides whether to finally disapprove the application.

(4) The permitting authority will either initially approve or issue a final disapproval of the application within 90 days after it notifies the owner or operator of an intent to disapprove or within 30 days after the date additional information is received from the owner or operator; whichever is earlier.

(5) A final determination by the permitting authority to disapprove any application will be in writing and will specify the grounds on which the disapproval is based. If any application is finally disapproved, the owner or operator may submit a subsequent application concerning construction or reconstruction of the same major source, provided that the subsequent application has been amended in response to the stated grounds for the prior disapproval.

(6) An initial decision to approve an application for a MACT determination will be set forth in the Notice of MACT Approval as described in paragraph (g) of this section.

(g) *Notice of MACT Approval.* (1) The Notice of MACT Approval will contain a MACT emission limitation (or a MACT work practice standard if the permitting authority determines it is not feasible to prescribe or enforce an emission standard) to control the emissions of HAP. The MACT emission limitation or standard will be determined by the permitting authority and will conform to the principles set forth in paragraph (d) of this section.

(2) The Notice of MACT Approval will specify any notification, operation and maintenance, performance testing, monitoring, reporting and record keeping requirements. The Notice of MACT Approval shall include:

(i) In addition to the MACT emission limitation or MACT work practice standard established under this subpart, additional emission limits, production limits, operational limits or other terms and conditions necessary to ensure Federal enforceability of the MACT emission limitation;

(ii) Compliance certifications, testing, monitoring, reporting and record keeping requirements that are consistent with the requirements of §70.6(c) of this chapter;

(iii) In accordance with section 114(a)(3) of the Act, monitoring shall be capable of demonstrating continuous compliance during the applicable reporting period. Such monitoring data shall be of sufficient quality to be used as a basis for enforcing all applicable requirements established under this subpart, including emission limitations;

(iv) A statement requiring the owner or operator to comply with all applicable requirements contained in subpart A of this part;

(3) All provisions contained in the Notice of MACT Approval shall be federally enforceable upon the effective date of issuance of such notice, as provided by paragraph (j) of this section.

(4) The Notice of MACT Approval shall expire if construction or reconstruction has not commenced within 18 months of issuance, unless the permitting authority has granted an extension which shall not exceed an additional 12 months.

(h) *Opportunity for public comment on the Notice of MACT Approval.* (1) The permitting authority will provide opportunity for public comment on the Notice of MACT Approval, including, at a minimum:

(i) Availability for public inspection in at least one location in the area affected of the information submitted by the owner or operator and of the permitting authority's initial decision to approve the application;

(ii) A 30-day period for submittal of public comment; and

(iii) A notice by prominent advertisement in the area affected of the location of the source information and initial decision specified in paragraph (h)(1)(i) of this section.

(2) At the discretion of the permitting authority, the Notice of MACT Approval setting forth the initial decision to approve the application may become final automatically at the end of the comment period if no adverse comments are received. If adverse comments are received, the permitting authority shall have 30 days after the end of the comment period to make any necessary revisions in its analysis and decide whether to finally approve the application.

(i) *EPA notification.* The permitting authority shall send a copy of the final Notice of MACT Approval, notice of approval of a title V permit application incorporating a MACT determination (in those instances where the owner or operator either is required or elects to obtain such a permit before construction or reconstruction), or other notice of approval issued pursuant to paragraph (c)(2)(ii) of this section to the Administrator through the appropriate Regional Office, and to all other State and local air pollution control agencies having jurisdiction in affected States.

(j) *Effective date.* The effective date of a MACT determination shall be the date the Notice of MACT Approval becomes final, the date of issuance of a title V permit incorporating a MACT determination (in those instances where the owner or operator either is required or elects to obtain such a permit before construction or reconstruction), or the date any other notice of approval issued pursuant to paragraph (c)(2)(ii) of this section becomes final.

(k) *Compliance date.* On and after the date of start-up, a constructed or reconstructed major source which is subject to the requirements of this subpart shall be in compliance with all applicable requirements specified in the MACT determination.

(l) *Compliance with MACT determinations.* (1) An owner or operator of a constructed or reconstructed major source that is subject to a MACT determination shall comply with all requirements in the final Notice of MACT Approval, the title V permit (in those instances where the owner or operator either is required or elects to obtain such a permit before construction or reconstruction), or any other final notice of approval issued pursuant to paragraph (c)(2)(ii) of this section, including but not limited to any MACT emission limitation or MACT work practice standard, and any notification, operation and maintenance, performance testing, monitoring, reporting, and recordkeeping requirements.

(2) An owner or operator of a constructed or reconstructed major source which has obtained a MACT determination shall be deemed to be in compliance with section 112(g)(2)(B) of the Act only to the extent that the constructed or reconstructed major source is in compliance with all requirements set forth in the final Notice of MACT Approval, the title V permit (in those instances where the owner or operator either is required or elects to obtain such a permit before construction or reconstruction), or any other final notice of approval issued pursuant to paragraph (c)(2)(ii) of this section. Any violation of such requirements by the owner or operator shall be deemed by the permitting authority and by EPA to be a violation of the prohibition on construction or reconstruction in section 112(g)(2)(B) for whatever period the owner or operator is determined to be in violation of such requirements, and shall subject the owner or operator to appropriate enforcement action under the Act.

(m) *Reporting to the Administrator.* Within 60 days of the issuance of a final Notice of MACT Approval, a title V permit incorporating a MACT determination (in those instances where the owner or operator either is required or elects to obtain such a permit before construction or reconstruction), or any other final notice of approval issued pursuant to paragraph (c)(2)(ii) of this section, the permitting authority shall provide a copy of such notice to the Administrator, and shall provide a summary in a compatible electronic format for inclusion in the MACT data base.

[61 FR 68401, Dec. 27, 1996]

Back to Top

§63.44 Requirements for constructed or reconstructed major sources subject to a subsequently promulgated MACT standard or MACT requirement.

(a) If the Administrator promulgates an emission standard under section 112(d) or section 112(h) of the Act or the permitting authority issues a determination under section 112(j) of the Act that is applicable to a stationary source or group of sources which would be deemed to be a constructed or reconstructed major source under this subpart before the date that the owner or operator has obtained a final and legally effective MACT determination under any of the review options available pursuant to §63.43, the owner or operator of the source(s) shall comply with the promulgated standard or determination rather than any MACT determination under section 112(g) by the permitting authority, and the owner or operator shall comply with the promulgated standard by the compliance date in the promulgated standard.

(b) If the Administrator promulgates an emission standard under section 112(d) or section 112(h) of the Act or the permitting authority makes a determination under section 112(j) of the Act that is applicable to a stationary source or group of sources which was deemed to be a constructed or reconstructed major source under this subpart and has been subject to a prior case-by-case MACT determination pursuant to §63.43, and the owner and operator obtained a final and legally effective case-by-case MACT determination prior to the promulgation date of such emission standard, then the permitting authority shall (if the initial title V permit has not yet been issued) issue an initial operating permit which incorporates the emission standard or determination, or shall (if the initial title V permit has been issued) revise the operating permit according to the reopening procedures in 40 CFR part 70 or part 71, whichever is relevant, to incorporate the emission standard or determination.

(1) The EPA may include in the emission standard established under section 112(d) or section 112(h) of the Act a specific compliance date for those sources which have obtained a final and legally effective MACT determination under this subpart and which have submitted the information required by §63.43 to the EPA before the close of the public comment period for the standard established under section 112(d) of the Act. Such date shall assure that the owner or operator shall comply with the promulgated standard as expeditiously as practicable, but not longer than 8 years after such standard is promulgated. In that event, the permitting authority shall incorporate the applicable compliance date in the title V operating permit.

(2) If no compliance date has been established in the promulgated 112(d) or 112(h) standard or section 112(j) determination, for those sources which have obtained a final and legally effective MACT determination under this subpart, then the permitting authority shall establish a compliance date in the permit that assures that the owner or operator shall comply with

the promulgated standard or determination as expeditiously as practicable, but not longer than 8 years after such standard is promulgated or a section 112(j) determination is made.

(c) Notwithstanding the requirements of paragraphs (a) and (b) of this section, if the Administrator promulgates an emission standard under section 112(d) or section 112(h) of the Act or the permitting authority issues a determination under section 112(j) of the Act that is applicable to a stationary source or group of sources which was deemed to be a constructed or reconstructed major source under this subpart and which is the subject of a prior case-by-case MACT determination pursuant to §63.43, and the level of control required by the emission standard issued under section 112(d) or section 112(h) or the determination issued under section 112(j) is less stringent than the level of control required by any emission limitation or standard in the prior MACT determination, the permitting authority is not required to incorporate any less stringent terms of the promulgated standard in the title V operating permit applicable to such source(s) and may in its discretion consider any more stringent provisions of the prior MACT determination to be applicable legal requirements when issuing or revising such an operating permit.

[61 FR 68404, Dec. 27, 1996

Appendix B

MACT Y Regulations and History

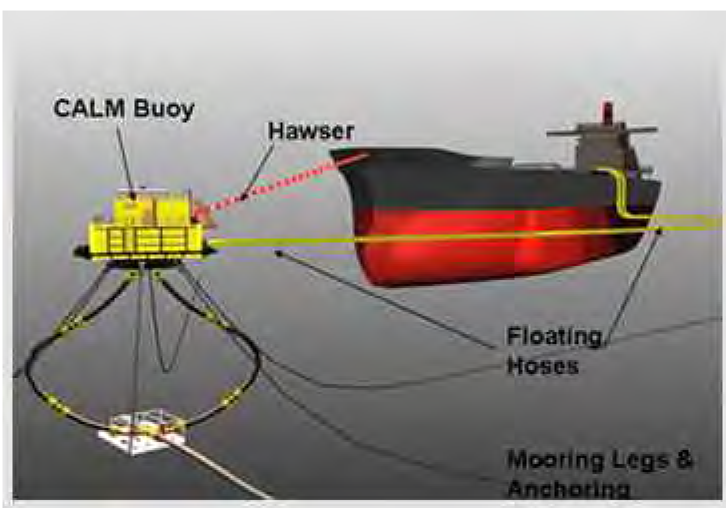
Deepwater Port Act Licensing of a Single-Point Mooring System:

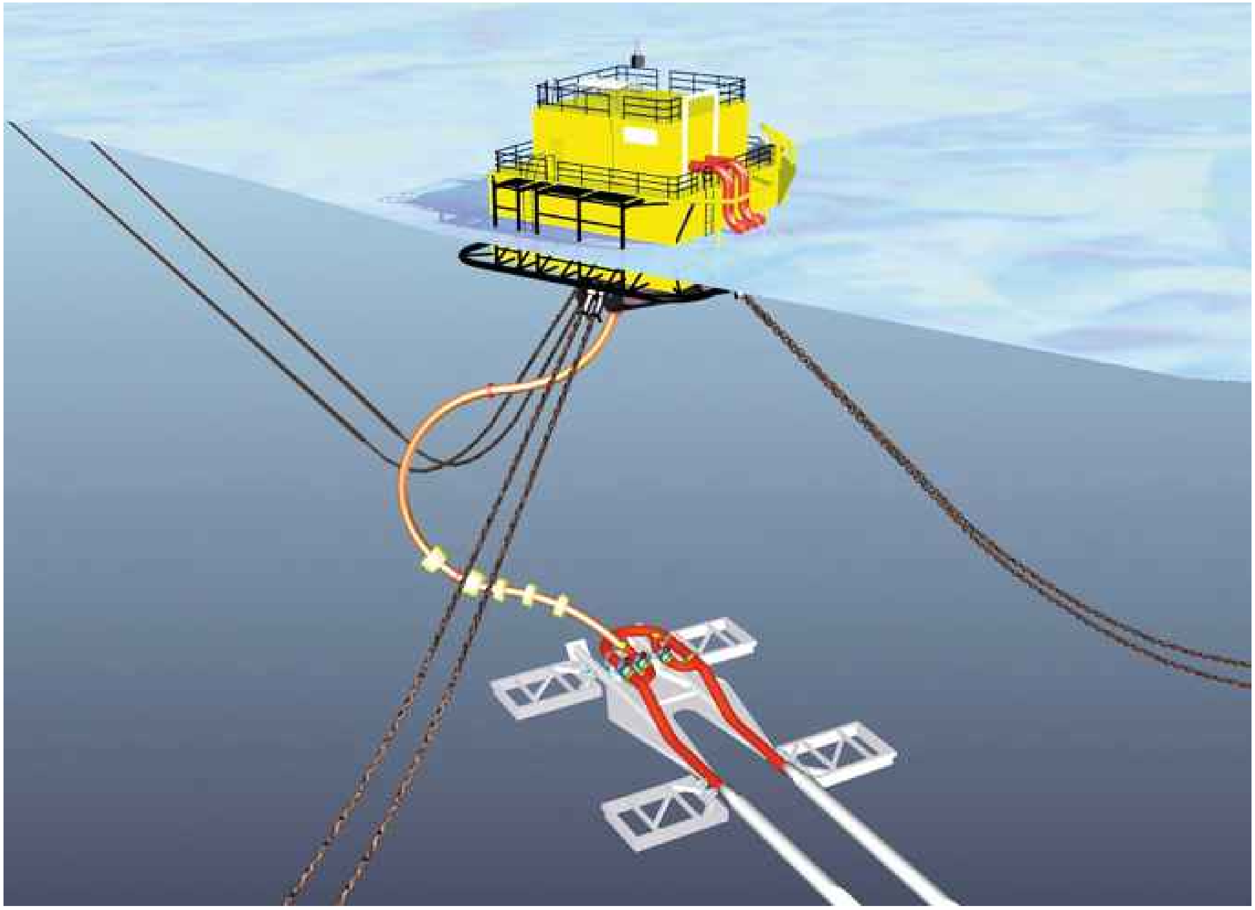
MACT Authorities Appendix

---

1. Single Point Mooring Systems in Operation
2. Clean Air Act § 112(a)(3)
3. Proposed MACT Y Rule Language
4. 40 C.F.R. § 63.561
5. EPA's TSD and Response to Comments Regarding the MACT Y Rulemaking
6. Bay Area Air Quality Management District Comments on the Proposed MACT Y Rulemaking
7. Photograph of the Chevron Richmond Long Wharf
8. Photograph of the Phillips 66 Rodeo Terminal
9. U.S. Coast Guard Regulations: Marine Vapor Control Systems, 33 C.F.R, Part 154, Subpart P

Single Point Mooring Systems in Operation


CALM Buoy
Hawser
Floating Hoses
Mooring Legs & Anchoring



Clean Air Act §112(a)(3):

Basis for Setting MACT for New and Existing Sources

42 U.S.C.A. § 7412

§ 7412. Hazardous air pollutants

Effective: August 5, 1999
Currentness

(a) Definitions

For purposes of this section, except subsection (r) of this section--

(1) Major source

The term "major source" means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants. The Administrator may establish a lesser quantity, or in the case of radionuclides different criteria, for a major source than that specified in the previous sentence, on the basis of the potency of the air pollutant, persistence, potential for bioaccumulation, other characteristics of the air pollutant, or other relevant factors.

(2) Area source

The term "area source" means any stationary source of hazardous air pollutants that is not a major source. For purposes of this section, the term "area source" shall not include motor vehicles or nonroad vehicles subject to regulation under subchapter II of this chapter.

(3) Stationary source

The term "stationary source" shall have the same meaning as such term has under section 7411(a) of this title.

(4) New source

The term "new source" means a stationary source the construction or reconstruction of which is commenced after the Administrator first proposes regulations under this section establishing an emission standard applicable to such source.

(5) Modification

emission standard applies, through application of measures, processes, methods, systems or techniques including, but not limited to, measures which--

(A) reduce the volume of, or eliminate emissions of, such pollutants through process changes, substitution of materials or other modifications,

(B) enclose systems or processes to eliminate emissions,

(C) collect, capture or treat such pollutants when released from a process, stack, storage or fugitive emissions point,

(D) are design, equipment, work practice, or operational standards (including requirements for operator training or certification) as provided in subsection (h) of this section, or

(E) are a combination of the above.

None of the measures described in subparagraphs (A) through (D) shall, consistent with the provisions of section 7414(c) of this title, in any way compromise any United States patent or United States trademark right, or any confidential business information, or any trade secret or any other intellectual property right.

(3) New and existing sources

The maximum degree of reduction in emissions that is deemed achievable for new sources in a category or subcategory shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined by the Administrator. Emission standards promulgated under this subsection for existing sources in a category or subcategory may be less stringent than standards for new sources in the same category or subcategory but shall not be less stringent, and may be more stringent than--

(A) the average emission limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has emissions information), excluding those sources that have, within 18 months before the emission standard is proposed or within 30 months before such standard is promulgated, whichever is later, first achieved a level of emission rate or emission reduction which complies, or would comply if the source is not subject to such standard, with the lowest achievable emission rate (as defined by section 7501 of this title) applicable to the source category and prevailing at the time, in the category or subcategory for categories and subcategories with 30 or more sources, or

(B) the average emission limitation achieved by the best performing 5 sources (for which the Administrator has or could reasonably obtain emissions information) in the category or subcategory for categories or subcategories with fewer than 30 sources.

(4) Health threshold

With respect to pollutants for which a health threshold has been established, the Administrator may consider such threshold level, with an ample margin of safety, when establishing emission standards under this subsection.

Proposed MACT Y Rule Language:

Definitions of “Loading Berth” and “Offshore Loading Terminal”

40 CFR Part 63--Subpart Y

It is proposed that part 63, chapter I, title 40 of the Code of Federal Regulations is amended as follows:

1. The authority citation for part 63 continues to read as follows: Authority: Secs. 101, 112, 114, 116, 183(f) and 301 Clean Air Act, as amended (42 U.S.C. 7401, 7411, 7414, 7416, 7511b(f), 7601)

2. By adding a new subpart Y to read as follows:

Subpart Y--National Emission Standards for Marine Vessel Loading and Unloading Operations

Sec.

Subpart Y--National Emission Standards for Marine Vessel Loading and Unloading Operations

§ 63.560 Applicability.

(a) Maximum achievable control technology (MACT) standards. The provisions of this subpart as well as subpart A of this part apply to any existing and new marine vessel loading and unloading operations that are major sources of hazardous air pollutant

<u>Loading cycle</u> means the time period from the beginning of filling a marine vessel until flow to the control device ceases, as measured by the flow indicator.

<u>Loading berth</u> means the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill marine vessels. This includes those items necessary for offshore loading and/or lightering.

<u>Marine vessel</u> or <u>marine tank vessel</u> means any tank ship or tank barge that transports liquid product such as gasoline or crude oil in bulk.

<u>Nonvapor tight</u> means any marine vessel that does not pass the required vapor-tightness test.

<u>Offshore loading terminal</u> means an open-water location for mooring a marine tank vessel and loading liquids through subsea lines from shore.

<u>Operating parameter value</u> means a minimum or maximum value established for a control device or process parameter which, if achieved by itself or in combination with one or more other operating parameter values, determines that an owner or operator has complied with an applicable emission limitation or standard.

<u>Primary fuel</u> means the fuel providing the principal heat input to the device, and sustaining operation of the device without the addition of other fuels.

<u>Process heater</u> means a device that transfers heat liberated by burning fuel to fluids contained in tubes, including all fluids except water that is heated to produce steam.

marine vessel loaded at less than atmospheric pressure is assumed to be vapor tight for the purpose of this standard.

Volatile organic compound or VOC is as defined in 40 CFR 51.100(s) of this chapter.

§ 63.562 Standards.

(a) The owner or operator of an affected source under § 63.560(a), MACT standards, shall equip each terminal with a vapor collection system that is:

(1) Designed to collect all HAP vapors displaced from marine vessels during loading, and

(2) Designed to prevent any HAP vapors collected at one loading berth from passing through another loading berth to the atmosphere.

(b) The owner or operator of an affected source under § 63.560(a), MACT standards, shall limit the loading of marine vessels to those vessels that are vapor-tight and are connected to the vapor collection system unless the owner or operator is loading a vessel with a commodity for which the owner or operator has made a determination, pursuant to section 63.565(d), that control of emissions from that commodity is not required to meet the emission limit specified in paragraph (c) of this section. Alternatively, the loading of nonvapor-tight vessels may occur under the conditions specified in § 63.563(a)(2)(iii)(B).

(c) The owner or operator of an existing affected source under § 63.560(a), MACT standards, shall reduce captured HAP emissions by 93 weight-percent as determined in § 63.565(c) and § 63.565(d).

(d) The owner or operator of a new affected source under § 63.560(a), MACT standards, shall reduce HAP emissions by 98 weight-percent.

(e) The owner or operator of an affected source under § 63.560(c), RACT standards, shall equip each terminal with a vapor collection system that is:

(1) Designed to collect VOC vapors displaced from marine vessels during loading of gasoline or crude oil, and

(2) Designed to prevent any VOC vapors collected at one loading berth from passing through another loading berth to the atmosphere.

(f) The owner or operator of an affected source under § 63.560(c), RACT standards, shall limit the loading of gasoline and/or crude oil marine vessels to those vessels that are vapor tight and are connected to the vapor collection system. The loading of nonvapor tight vessels can occur only under the conditions specified in § 63.563(a)(2)(iii)(B).

(g) The owner or operator of an affected source under § 63.560(c), RACT standards, shall reduce captured VOC emissions from gasoline or crude oil loading by 98 weight-percent when using a combustion device or reduce VOC emissions by 95 weight-percent when using a recovery device, as determined in § 63.565(c).

(h) The owner or operator of a new or existing affected source under § 63.560(a), MACT standards, shall prevent any HAP emissions from ballasting operations.

40 C.F.R. §63.561:

Final MACT Y Definitions of "Loading Berth" and "Offshore Loading Terminal"

40 C.F.R. § 63.561

§ 63.561 Definitions.

Effective: April 21, 2011
Currentness

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act or in subpart A of this part.

Affected source means a source with emissions of 10 or 25 tons, a new source with emissions less than 10 and 25 tons, a new major source offshore loading terminal, a source with throughput of 10 M barrels or 200 M barrels, or the VMT source, that is subject to the emissions standards in § 63.562.

Affirmative defense means, in the context of an enforcement proceeding, a response or a defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Air pollution control device or control device means a combustion device or vapor recovery device.

Ballasting operations means the introduction of ballast water into a cargo tank of a tankship or oceangoing barge.

Baseline operating parameter means a minimum or maximum value of a process parameter, established for a control device during a performance test where the control device is meeting the required emissions reduction or established as the manufacturer recommended operating parameter, that, if achieved by itself or in combination with one or more other operating parameters, determines if a control device is operating properly.

Boiler means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system.

Car-seal means a seal that is placed on a device used to change the position of a valve (e.g., from open to closed) in such a way that the position of the valve cannot be changed without breaking the seal.

Combustion device means all equipment, including, but not limited to, thermal incinerators, catalytic incinerators, flares, boilers, and process heaters used for combustion or destruction of organic vapors.

Commenced means, with respect to construction of an air pollution control device, that an owner or operator has undertaken a continuous program of construction or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction.

Commodity means a distinct product that a source loads onto marine tank vessels.

Continuous means, with respect to monitoring, reading and recording (either in hard copy or computer readable form) of data values measured at least once every 15 minutes.

Crude oil means a naturally occurring mixture consisting predominantly of hydrocarbons and/or sulfur, nitrogen, and oxygen derivatives of hydrocarbons that is removed from the earth in a liquid state or is capable of being so removed.

Exceedance or Variance means, with respect to parametric monitoring, the operating parameter of the air pollution control device that is monitored as an indication of proper operation of the control device is outside the acceptable range or limits for the baseline parameter given in § 63.563(b)(4) through (9).

Excess emissions means, with respect to emissions monitoring, the concentration of the outlet stream of the air pollution control device is outside the acceptable range or limits for the baseline concentration given in § 63.563(b)(4) through (9).

Flow indicator means a device that indicates whether gas flow is present in a line or vent system.

Gasoline means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kPa (4.0 psia) or greater, that is used as a fuel for internal combustion engines.

Impurity means HAP substances that are present in a commodity or that are produced in a process coincidentally with the primary product or commodity and that are 0.5 percent total HAP by weight or less. An impurity does not serve a useful purpose in the production or use of the primary product or commodity and is not isolated.

Leak means a reading of 10,000 parts per million volume (ppmv) or greater as methane that is determined using the test methods in Method 21, appendix A of part 60 of this chapter.

Lightering or Lightering operation means the offshore transfer of a bulk liquid cargo from one marine tank vessel to another vessel.

Loading berth means the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill marine tank vessels. The loading berth includes those items necessary for an offshore loading terminal.

Loading cycle means the time period from the beginning of filling a single marine tank vessel until commodity flow to the marine tank vessel ceases.

Maintenance allowance means a period of time that an affected source is allowed to perform maintenance on the loading berth without controlling emissions from marine tank vessel loading operations.

Marine tank vessel loading operation means any operation under which a commodity is bulk loaded onto a marine tank vessel from a terminal, which may include the loading of multiple marine tank vessels during one loading operation. Marine tank vessel loading operations do not include refueling of marine tank vessels.

Marine vessel or Marine tank vessel means any tank ship or tank barge that transports liquid product such as gasoline or crude oil in bulk.

Nonvapor-tight means any marine tank vessel that does not pass the required vapor-tightness test.

Offshore loading terminal means a location that has at least one loading berth that is 0.81 km (0.5 miles) or more from the shore that is used for mooring a marine tank vessel and loading liquids from shore.

Primary fuel means the fuel that provides the principal heat input to the device. To be considered primary, the fuel must be able to sustain operation of the device without the addition of other fuels.

Process heater means a device that transfers heat liberated by burning fuel to fluids contained in tubes, including all fluids except water that are heated to produce steam.

Recovery device means an individual unit of equipment, including, but not limited to, a carbon adsorber, condenser/refrigeration unit, or absorber that is capable of and used for the purpose of removing vapors and recovering liquids or chemicals.

Routine loading means, with respect to the VMT source, marine tank vessel loading operations that occur as part of normal facility operation over a loading berth when no loading berths are inoperable due to maintenance.

Secondary fuel means any fuel other than the primary fuel. The secondary fuel provides supplementary heat in addition to the heat provided by the primary fuel and is generally fired through a burner other than the primary burner.

Source(s) means any location where at least one dock or loading berth is bulk loading onto marine tank vessels, except offshore drilling platforms and lightering operations.

Source(s) with emissions less than 10 and 25 tons means major source(s) having aggregate actual HAP emissions from marine tank vessel loading operations at all loading berths as follows:

(1) Prior to the compliance date, of less than 9.1 Mg (10 tons) of each individual HAP calculated on a 24–month annual average basis after September 19, 1997 and less than 22.7 Mg (25 tons) of all HAP combined calculated on a 24–month annual average basis after September 19, 1997, as determined by emission estimation in § 63.565(l) of this subpart; and

(2) After the compliance date, of less than 9.1 Mg (10 tons) of each individual HAP calculated annually after September 20, 1999 and less than 22.7 Mg (25 tons) of all HAP combined calculated annually after September 20, 1999, as determined by emission estimation in § 63.565(l) of this subpart.

Source(s) with emissions of 10 or 25 tons means major source(s) having aggregate actual HAP emissions from marine tank vessels loading operations at all loading berths as follows:

(1) Prior to the compliance date, emissions of 9.1 Mg (10 tons) or more of each individual HAP calculated on a 24–month annual average basis after September 19, 1997 or of 22.7 Mg (25 tons) or more of all HAP combined calculated on a 24–month annual average basis after September 19, 1997, as determined by emission estimation in § 63.565(l); or

(2) After the compliance date, emissions of 9.1 Mg (10 tons) or more of each individual HAP calculated annually after September 20, 1999 or of 22.7 Mg (25 tons) or more of all HAP combined calculated annually after September 20, 1999, as determined by emission estimation in § 63.565(l).

Source(s) with throughput less than 10 M barrels and 200 M barrels means source(s) having aggregate loading from marine tank vessel loading operations at all loading berths as follows:

(1) Prior to the compliance date, of less than 1.6 billion liters (10 million (M) barrels) of gasoline on a 24–month annual average basis and of less than 32 billion liters (200 M barrels) of crude oil on a 24–month annual average basis after September 19, 1996; and

(2) After the compliance date, of less than 1.6 billion liters (10 M barrels) of gasoline annually and of less than 32 billion liters (200 M barrels) of crude oil annually after September 21, 1998.

Source(s) with throughput of 10 M barrels or 200 M barrels means source(s) having aggregate loading from marine tank vessel loading operations at all loading berths as follows:

(1) Prior to the compliance date, of 1.6 billion liters (10 M barrels) or more of gasoline on a 24–month annual average basis or of 32 billion liters (200 M barrels) or more of crude oil on a 24–month annual average basis after September 19, 1996; or

(2) After the compliance date, of 1.6 billion liters (10 M barrels) or more of gasoline annually or of 32 billion liters (200 M barrels) or more of crude oil annually after September 21, 1998.

Terminal means all loading berths at any land or sea based structure(s) that loads liquids in bulk onto marine tank vessels.

Twenty-four-month (24–month) annual average basis means annual HAP emissions, with respect to MACT standards, or annual loading throughput, with respect to RACT standards, from marine tank vessel loading operations averaged over a 24–month period.

Valdez Marine Terminal (VMT) source means the major source that is permitted under the Trans–Alaska Pipeline Authorization Act (TAPAA) (43 U.S.C. § 1651 et seq.). The source is located in Valdez, Alaska in Prince William Sound.

Vapor balancing system means a vapor collection system or piping system that is designed to collect organic HAP vapors displaced from marine tank vessels during marine tank vessel loading operations and that is designed to route the collected organic HAP vapors to the storage vessel from which the liquid being loaded originated or to compress collected organic HAP vapors and commingle with the raw feed of a process unit.

Vapor collection system means any equipment located at the source, i.e., at the terminal, that is not open to the atmosphere, that is composed of piping, connections, and flow inducing devices, and that is used for containing and transporting vapors displaced during the loading of marine tank vessels to a control device or for vapor balancing. This does not include the vapor collection system that is part of any marine vessel vapor collection manifold system.

Vapor-tight marine vessel means a marine tank vessel that has demonstrated within the preceding 12 months to have no leaks. A marine tank vessel loaded at less than atmospheric pressure is assumed to be vapor tight for the purpose of this standard.

Volatile organic compounds or VOC is as defined in 40 CFR 51.100(s) of this chapter.

Credits

[76 FR 22596, April 21, 2011]

SOURCE: 57 FR 61992, Dec. 29, 1992; 60 FR 48399, Sept. 19, 1995, unless otherwise noted.

AUTHORITY: 42 U.S.C. 7401 et seq.

Notes of Decisions (1)

Current through March 8, 2018; 83 FR 9817.

EPA's TSD and Response to Comments Regarding the MACT Y Rulemaking

EPA-453/R-95-014

United States Environmental Protection Agency | Office of Air Quality Planning and Standards Research Triangle Park, NC 27711 | EPA-453/R-95-014 July 1995

Air

EPA

FEDERAL STANDARDS FOR MARINE TANK VESSEL LOADING OPERATIONS AND NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR MARINE TANK VESSEL LOADING OPERATIONS

Technical Support Document for Final Standards:

Summary of Public Comments and Responses

FR

2.3.2 Offshore Terminals/Offshore Production

Comment: Six commenters (28, 30, 34, 73, 127, 133) supported the creation of a separate subcategory for offshore facilities. One commenter (28) added that a significant reason not to require control at offshore facilities would be the lack of any population that would be impacted by HAP emissions from these operations. This commenter applied the same standard to facilities located in remote areas. Another commenter (30) described a host of factors relative to differing economic considerations associated with offshore terminals and provided a definition of "offshore terminal".

One commenter (36) recommended that terminal facilities that operate docks or platforms extending one-half mile or more into the water be classified as "on-shore terminals," consistent with Federal law, but that such terminals be exempted from the vapor control requirements proposed in this rulemaking.

Another commenter (130) stated that the grouping of offshore terminals into a subcategory is appropriate but stated that the Agency's use of a one-half mile limit is arbitrary. This commenter's terminal is less than one-half mile from shore, but is over two miles from a refinery. The commenter requested that the final regulations address such terminals so that they would not be required to control emissions. Another commenter (137) also stated that the one-half mile limit is arbitrary and maintained that the main consideration should be if a terminal is contiguous to a refinery.

One commenter (41) supported the proposed requirement that offshore terminals meet the same requirements as onshore terminals. This commenter continued by stating "unless it can be shown that emissions from such terminals have no risk to the most exposed person." Another commenter (87) did not support grouping offshore facilities into source categories unless the MACT requirements are at least as stringent as those for onshore facilities.

One commenter (73) stated HAP emissions from offshore terminals have a much lower potential for human exposure due to the distance from the emissions source to any receptors. Only if the terminal by itself is determined to be a major source should the terminal be subject to any applicable MACT standards.

Two commenters (28, 73) stated that noncontiguous marine loading/unloading facilities should not be regulated under the proposed MACT rules unless the marine terminal by itself is determined to be a major source.

One commenter (80) disagreed with the separate facility designation and cited two facilities with loading operations that occur more than 0.5 miles offshore; the commenter considers these sources "contiguous."

Several commenters (34, 72, 73) supported EPA's separate facility designation for offshore terminals that are one-half mile or greater from shore. One commenter (30) suggested EPA create subcategories within the offshore terminal source category to reflect the different sizes of terminals, the quantities of products handled, and the fundamental differences between crude oil production platforms and product terminal platforms. This commenter and one other (72) suggested language for the definition of the term "offshore terminal."

One commenter (127) stated that offshore terminals face significant control costs that are several times the national ceiling and many times higher than the national average. The commenter also stated that control requirements would result in significant technological difficulties that are not yet fully understood. The commenter stated that the State regulations governing the Riverhead, Long Island terminal do not require control of this offshore terminal and that Federal regulation should take a similar approach.

One commenter (136) stated that none of the offshore terminals of which the commenter is aware presently control emissions. Therefore, the commenter stated that the MACT floor for a subcategory of offshore terminals would be uncontrolled.

One commenter (140) favored the establishment of a subcategory for offshore terminals provided that the definition of "offshore terminal" be structured to include docks or piers having loading arms that are at least one-half mile from shore and may not necessarily incorporate subsea lines. The commenter stated that these types of terminals would face similar costs and technical difficulties in installing control equipment as the offshore terminals with subsea lines.

<u>Response</u>: The Agency is in agreement with many of the comments received. The Agency maintains its position as stated in the proposed rule that a marine tank vessel loading operation that is at least one-half mile offshore is not part of a land-based contiguous site. The Agency agrees with commenters that these offshore terminals should be considered separate (stand alone) sources because many are supplied solely by subsea lines and others, by definition, have at least one berth that is one-half mile or more beyond the shore line. Offshore loading operations with subsea lines in particular require the permitting of either additional subsea lines to carry vapors or permitting of docks or platforms. If permits are unavailable for these offshore terminals, compliance with the standards would be impossible. These factors result in significantly higher costs compared to onshore terminals. Additionally, these terminals pose less of a health risk to any surrounding population. The Agency also agrees with several of the commenters that these sources warrant the establishment of a separate subcategory because of the differences in the feasibility and cost of controlling emissions at these offshore terminals.

Once the Agency determined that a subcategory existed for these offshore terminals, a MACT floor determination was made and MACT selected. The data made available to the Agency indicates that there are fewer than 20 offshore terminals having subsea lines. None of these terminals presently control emissions from marine tank vessel loading. The Agency was also made aware of additional offshore terminals that do not have subsea lines. Two of these terminals for which the Agency has information presently control emissions. Based on the information available to the Agency, the MACT floor for existing sources in this subcategory is no control of HAP emissions. The MACT floor for new offshore sources is 95 percent reduction of emissions. (See Docket A-90-44, Item Number IV-B-2 for additional discussion of the MACT floor determination for this subcategory). Data submitted by commenters show that the costs associated with the control of offshore terminals are between two and five times more expensive than comparable onshore control techniques (see Docket A-90-44, Item numbers IV-D-108 and IV-D-136). Because of the poor cost effectiveness resulting from these significantly higher costs, as well as the environmental and technical challenges (discussed above) associated with requiring control more efficient than the MACT floor, the Agency has selected the MACT floor level of no control for offshore marine tank vessel loading operations.

The Agency also determined that offshore terminals loading 10 million barrels per year or more of gasoline or 200 million barrels or more of crude oil should not be required to control emissions of VOC or HAP. The comments that noted the significantly higher costs and poor cost effectiveness of these sources (see previous paragraph) would make control requirements unreasonable for these offshore terminals (See Docket No. A-90-44, item No. IV-B-2 for additional information on the determination of MACT floors for the final standards.). Regarding the comment from Commenter 36, EPA is using the term "offshore terminals" solely for the sake of simplicity and practicality in this rulemaking. The use of the term in this rulemaking should not have any effect on other programs. This approach is more straightforward and practical than the approach suggested by Commenter 36.

Comment: One commenter (30) suggested EPA create subcategories within the offshore terminal source category to reflect the different sizes of terminals, the quantities of products handled, and the fundamental differences between crude oil production platforms and product terminal platforms. The commenter was concerned that EPA, in setting standards, should not penalize terminals that handle gasolines containing oxygenates (such as MTBE) to the oxygenated and reformulated gasoline requirements of the CAA.

Response: The Agency agrees that offshore terminals could be further subcategorized based on the types of commodities loaded, the size of the terminal, or by the type of operation with which the terminal is associated. However, the comments received did not contain sufficient information to justify further subcategorization of offshore terminals.

Bay Area Air Quality Management District:

Comments on the Proposed MACT Y Rulemaking

A-90-44
IV-D-80

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

July 18, 1994

To: Air Docket Section (6102)
Room M1500
U.S. Environmental Protection Agency
401 M Street, S.W.
Washington, DC, 20460

RECEIVED
JUL 2 1994
EPA AIR DOCKET

Attention: Docket Number A-90-44

Dear Sir/Madam,

Enclosed are comments on the proposed rule under 40 CFR Part 63, Subpart Y, Federal Standards for Marine Tank Vessel Loading and Unloading Operations and National Emission Standards for Hazardous Air Pollutants for Marine Tank Vessel Loading and Unloading Operations (pursuant to Section 112(d) of the 1990 Amendments to the Clean Air Act, and Section 183(f) of the Act). These comments are respectfully submitted by the Bay Area Air Quality Management District in San Francisco, California.

The District has devoted considerable staff time to participating in and commenting on the development of rules pursuant to Title III of the Amendments. We are concerned about federal requirements for sources of HAPs because existing permitting and risk management programs in the Bay Area address many of the same toxics concerns. We have numerous Rules and Regulations in place which limit emissions from the significant source categories in our region. In particular, our Regulation 8, Rule 44 limits emissions from Marine Vessel Loading Terminals, and Regulation 8, Rule 46 limits emissions from Marine Tank Vessel to Marine Tank Vessel Loading. As you might expect, we believe it is critical that the rulemaking efforts at EPA recognize the importance of established local programs, and provide flexibility to minimize negative impacts on these programs wherever possible.

The proposed RACT/MACT effort for this source category represents an important step in program integration. We support the effort to control VOC and HAP emissions from major marine terminal sources. At the same time, we have identified several issues that need to be addressed, in order to improve the clarity and efficacy of the proposed rule. We have identified three critical issues: (1) the treatment of the MACT floor(s) and MACT standard(s) for existing marine

939 ELLIS STREET • SAN FRANCISCO, CALIFORNIA 94109 • (415) 771-6000 • FAX (415) 928-8560

RECYCLED PAPER

terminals; (2) a number of emission units and/or operations neglected in the control requirements; and (3) the treatment of emissions averaging. The attached comments provide more detail regarding these and other issues. We urge you to give them careful consideration.

The District appreciates the opportunity to work with EPA in developing the federal toxics program. The proposed rule for Marine Tank Vessel Loading represents an important effort in comprehensive, integrated source control; we hope our comments are useful to you in preparing your next draft. The District would be happy to provide you with any information we can regarding control options and equipment configuration and uses within our jurisdiction. Please contact us if you feel this would be helpful. If you have any questions regarding these comments, please contact Bob Nishimura, at (415) 749-4679, or Barbara Lee at (415) 749-4709.

Thank you for the opportunity to comment on this document. We look forward to working with you in the future.

Sincerely,

Milton Feldstein

Milton Feldstein
Air Pollution Control Officer

/MF:bal
attachments

cc: Mr. Bruce Jordan
Emission Standards Division (MD-13)
U.S. Environmental Protection Agency
Research Triangle Park, NC, 27711

Mr. Robert Fletcher
California Air Resources Board, Toxic Air Contaminant Control Branch
2020 L Street
P.O. Box 2815
Sacramento, CA 95812

Mr. David P. Howekamp
Director, Air and Toxics Division
U.S. Environmental Protection Agency, Region IX
75 Hawthorne Street
San Francisco, CA 94105

Mr. Stewart J. Wilson
California Air Pollution Control Officers Association
3232 Western Drive
Cameron Pk, CA 95682

William Becker, Executive Director
STAPPA and ALAPCO
44 North Capitol St. N.W.
Washington, D.C. 20001

Mr. David Markwordt
Chemicals and Petroleum Branch, ESD, (MD-13)
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

This attachment details the comments of the Bay Area Air Quality Management District on the proposed RACT/MACT rulemaking for Marine Vessel Loading. Comments are grouped into critical issues and additional issues.

Critical Issues:

1. **MACT Floor Determination-** In general, the treatment of the MACT floor for new sources is acceptable, although we have included comments on the pollution prevention alternative discussed in the preamble document, in response to EPA's request for comment (see Additional Issues). The floor determination for existing sources, however, has several problems. The proposal subcategorizes the source category according to the magnitude of emissions, and establishes separate floors for the two subcategories. We disagree, in principle, with the approach taken to the subcategorization, and we disagree with the control determinations made for the subcategories.

   a) **Subcategorization-** The Act instructs EPA to list "all categories and subcategories of major sources and area sources (listed under paragraph (3)) of the air pollutants listed pursuant to subsection (b)." It is unfortunately vague on the criteria for subcategorization. In general, EPA has grouped sources based on functional similarity and on similarity in the type of emissions, and the way in which the emissions occur (for example, through a stack, as opposed to from a leaking component). Another consideration is typically the technical feasibility of control, as in, whether a certain type of control device can technically be applied to all sources in the category or subcategory. The District recognizes the need to group sources according to these criteria (the distinction between transfer and non-transfer drycleaning machines is a good example of subcategorization, as is the distinction between wastewater treatment and process vent emissions under the HON). We believe that the attempt made at subcategorization of existing sources subject to the MACT requirements in this proposal is arbitrary, and is not defensible.

      There is no clear line at 1.1 tons per year of HAP emissions that distinguishes facilities on a functional basis, or according to the type or mechanism of the emissions. Some of the sources under 1.1 tons per year may operate sporadically, rather than regularly, and some of the sources may be area sources, not major sources. If this is the basis for the subcategorization, the subcategory should be drawn around sources with similar operating cycles, not the arbitrary threshold of 1.1 tons per year. If the intent is to exclude area sources, a simple exclusion of area sources should be provided, or a "de minimis" emission level established for applicability of the rule.

b) **MACT: sources above 1.1 tons per year-** EPA has proposed a MACT control level of 93% for sources emitting more than 1.1 tons per year of HAP. This is lower than the proposed RACT level of control. We believe that it is inappropriate to set MACT below RACT. In the preamble to the proposed rule, EPA indicates that there was little practical difference between 93% and 95% control, but that the 93% would allow sources to use a vapor recovery device at 95%, and still elect to "exclude" certain loading operations from control. We believe it is inappropriate to lower the required control level in order to promote emissions averaging (see Critical Issue #3). Further, the preamble acknowledges that there is no control device that corresponds to a control level of 93%, and that the device capable of achieving 93% is also capable of achieve 95%. In other words, it is equally cost-effective and as technically feasible to achieve 95% control, rather than the proposed 93%.

The language of the Act is quite clear on the point of selecting a control level. The Administrator is instructed (under 112(d)(2)) to promulgate standards for new or existing sources of HAP that "*<u>require the maximum degree of reduction in emissions</u> of the hazardous air pollutants subject to this section (including a prohibition on such emissions, where achievable) that the Administrator, taking into consideration the cost of achieving such emissions reduction, and any nonair quality health and environmental impacts and energy requirements, determines is achievable*...(emphasis ours)." The discussion of MACT for existing sources sets a floor at "the average emission limitation achieved by the best performing 12 percent of the existing sources", but this is a floor, not a ceiling. The Act *allows* EPA to set existing source MACT at a level less stringent than new source MACT, but requires that it not be any lower than the floor. Based on the language of the Act, and on EPA's floor calculation, we believe that MACT should be set at 95% control for existing sources.

c) **MACT: sources below 1.1 tons per year-** EPA took specific comment on the mechanism for determining the MACT floor, and whether "average" refers to the *mean*, *median*, or *mode*. The Bay Area strongly believes that the best reading of the Act is the arithmetic *mean*. Our comments on the reopening of the HON (submitted April 8, 1994, under Docket A-90-19) give a detailed explanation of our position. We encourage EPA to review them. Beyond this, however, the District believes it is critical that EPA maintain a consistent approach to determination of the MACT floor. If the calculation of the "average emission limitation" is changed on a case-by-case basis to yield a particular, desired result, any given floor determination will be vulnerable to legal challenge, and the overall process will be weakened. If EPA believes that there is sufficient data to justify exempting these sources from control, the decision should be presented as a proposed exemption, not as a variant floor determination.

The Bay Area currently regulates marine loading operations with emissions below 1.1 tons per year. Sources are required to meet 95% control, and we have found this to be cost-effective. We phased in the requirements for small terminals (total annual loading less than 1 million barrels), extending the compliance period by 1 year. In addition, our rule exempts loading events less than 1,000 barrels. We believe that if EPA wishes to exempt smaller facilities (or small operations at large facilities) from control at this time, there must be a clear commitment to consider these sources under the urban area source program, or when this source category is reviewed for residual risk.

2. **Sources Subject to Regulation-** There are a number of sources that the District believes should be subject to regulation under this proposal. If EPA determines that inclusion of these sources is beyond the scope of this rule, the sources should be listed in separate categories, and a commitment made to regulate them.

a) **Applicability of RACT-** The applicability of the RACT portion of this proposal is restricted to facilities loading gasoline or crude oil at certain thresholds. The District notes that the marine loading facilities in the Bay Area load a wide variety of products; we believe that the throughput of products other than gasoline and crude oil should be considered in determining applicability of the standard. Although the HAP emission threshold may act as a surrogate in some cases, this threshold only applies to the MACT standard, and EPA has proposed a MACT level of control that is lower than the RACT level of control. An existing marine loading terminal at a SOCMI facility would therefore be subject to less stringent standards than a marine loading facility that only processes crude oil, for example, even if the products loaded at the SOCMI terminal were substantially more hazardous. This is inappropriate. We urge EPA to consider total loading throughput for the purposes of determining applicability; the products can be grouped according to relative toxicity (e.g., a group containing crude oil and other less hazardous materials/products, and a group containing gasoline and other more hazardous products, and perhaps a group of very hazardous products). In the Bay Area, we consider the loading of any fluid, including water, into a tank that previously contained organic liquid to be a source of VOC emissions because the loading of any material into an unpurged cargo tank generates VOC emissions.

In addition, we believe the throughput thresholds are too high. Loading gasoline into a cargo-tank that has not been purged of vapors since removal of the previous cargo results in emissions of 3.4 lbs VOC per 1000 gallons loaded. Assuming a terminal is handling only barges, and loading 5 million barrels per year, the emissions will be about 357 tons of VOC. This is 3.5 times higher than the major source level of 100 tons per year. The five million barrels correspond to 100 tons per year if it is assumed that the cargo tanks were all gas-free on loading. This is not a valid assumption, and even if the tanks are purged before loading, the purged vapors are still emitted. We would support the applicability thresholds as outlined in alternatives III or IV or Table 1, RACT Regulatory Alternatives, in the preamble to the rule. The level for gasoline in Alternative III is more appropriate, but we support the consideration of other products besides gasoline and crude oil.

b) **Applicability of MACT-** The proposed MACT standards are to apply to "any existing and new marine vessel loading and unloading operations that are major sources of hazardous air pollutant (HAP) emissions..." (Section 63.560(a)). First, the term "loading and unloading operations" is not defined in the rule. This should be rectified, or a different term should be used in the applicability statement. Second, it is unclear from the language whether loading operations that are not, in and of themselves, major sources are subject to the standard. We believe that non-major operations at major stationary sources should be subject to the standard. It appears that EPA is of the same mind, because Section 63.560(b) goes on to exempt operations emitting less than 1.1 tons per year of HAP. The major source threshold for total HAP emissions is 25 tons per year, so presumably, sources between 1.1 tons and 25 tons are subject to the standard; this is confusing because these are not major sources, but the rule does not specifically restrict applicability to sources that are part of a contiguous land-based facility. Further, while the preamble qualifies that the 1.1 tons per year is <u>uncontrolled</u>, the rule does not specifically state whether emissions are controlled or uncontrolled. The equations referenced in the rule (63.565(d)) calculate controlled and uncontrolled emissions. If the equations are to be relied on, a more specific reference is required.

c) **Fugitive sources of HAP-** The preamble to the proposed rule specifically states that fugitive sources are not considered as part of the marine loading operation (organic HAP storage, piping, pumping, and vapor leaks from seals, hatch covers, and pressure relief valves). Some of these sources may be subject to regulation under the HON, the Refinery MACT, or the Stage I Gasoline Distribution MACT, however it is unclear how applicability is divided. For example, at which point is the storage part of the HON facility versus the marine loading terminal? The same question applies to piping, pumping, etc. This is especially important because the proposed Stage I Gasoline Distribution MACT excludes marine loading operations, and transfer operations are not subject to regulation at all under the proposed Refinery MACT. It is important that these sources be regulated, and the emissions from them should be counted in determining applicability of this rule. We recommend that fugitive emissions from marine loading operations be addressed in the rule in order to provide greater clarity of the total marine loading requirements to the regulatory and regulated community.

d) **Contiguous facilities-** The preamble to the proposed rule refers to a distance of 0.5 miles as the "threshold" for considering terminals part of the land-based facility. The rule itself defines "offshore loading platform," but the term is not used elsewhere in the rule. The definition of "source" excludes "offshore drilling platforms and offshore lightering operations," but the applicability of the rule is based on "loading and unloading operations," not sources. Is it the intent of EPA to exclude offshore loading from the rule? If so, the Bay Area strongly objects to the proposal. We further believe that the 0.5 mile separation referred to in the preamble is not appropriate as defining contiguous source. Case-law has established that public waterways do not serve to separate one facility from another, if they are otherwise "contiguous." We have two facilities in the Bay Area with loading operations that occur more than 0.5 miles offshore. One is on a platform, and the other is on the end of a very long pier. Both operations are controlled, and both should be considered as part of the refinery from which the product originates.

e) **Lightering operations-** The Bay Area regulates the transfer of organic liquid cargo from one marine vessel tank to another marine vessel tank. Emissions are limited to 2 lbs VOC per 1,000 bbls of product transferred, or they must be controlled to 95%. We promulgated this regulation because the emissions from lightering operations are substantial, and we urge EPA to regulate this transfer operation. Vessel-to-vessel transfer is within the scope of the listed source category definition. Further, a vapor balance system would provide reasonable control at a comparatively low cost, and would improve the work environment for barge and tanker workers currently exposed to these emissions. If EPA believes that lightering operations are beyond the scope of this rulemaking, it should be established as a separate source category, listed, and scheduled for control.

f) **Emissions from "gas-free" operations-** It is common practice for Marine Vessels traveling within California (and Oregon and Washington) Coastal waters to purge their tanks of vapors prior to arrival at port. A cargo tank that is "gas-free" is assumed to have lower emissions than a tank carrying vapors. Because of meteorological patterns, emissions from "gas-free" operations can have a significant impact on onshore ozone levels. We urge EPA to prohibit purging of cargo tank vapors within U.S. Coastal waters.

3. **Emissions Averaging-** The proposed MACT level of control for existing sources sets a "floor" at 93% and allows sources to over-control some products while "excluding" other products from control, provided the facility meets the overall control level of 93%. This is, in essence, emissions averaging. The Bay Area has commented extensively on a number of proposals under Section 112 that provide some form of averaging or offsetting of emissions. We have the same concerns about averaging in this proposal. If facilities propose to "exclude" the loading of certain products from control requirements, the exclusion should be restricted according to the toxicity of the components. Carcinogenic compounds that have a high unit risk value should not be excluded from control, in favor of controlling the emissions of compounds with a lower unit risk value. This is especially critical for marine loading of products from the SOCMI industry. The rule should specifically allow State or local agencies to exclude the "averaging" portion of the rule without requiring review under Subpart E.

Additional Issues:

1. **New source MACT-** EPA has requested comment on the alternative to allow 95% efficiency for product recovery as MACT, in addition to the 98% destruction efficiency. The Bay Area would support that proposal, in the interest of furthering pollution prevention, but we feel compelled to point out that legally, the proposal would be vulnerable to challenge. The Act clearly mandates setting MACT to be no less stringent than the level of control achieved by the best performing similar source, which is at least 98% control with a vapor destruction device.

2. **Alternative emission limitation-** In the Bay Area, marine loading is subject to a percent reduction requirement, or a mass emission limitation. We recommend that EPA consider a limitation of 2 lbs per 1000 barrels loaded. Fugitive emissions should be considered in determining uncontrolled and controlled emissions.

3. **Leak standards-** The proposed rule should included leak standards and require inspection and maintenance on the storage, piping, pumping, and other fugitive sources.

4. **Pressure standards-** The proposed rule should clearly state that loading pressures cannot exceed 0.8 of the minimum setting for pressure relief valves. This is because the vapors displaced during loading will escape through pressure relief valves, if the system pressure is high enough. Further, fugitive emissions in general are a function of pressure, so a standard limiting loading pressure would be appropriate. The District believes that 1.0 psi is a reasonable level.

5. **Vapor-tightness-** The District does not support the provision to allow loading of non vapor-tight vessels under the conditions specified in Section 63.563(a)(2)(iii)(B). Vapor tightness should be required for all vessels, independent of the control level at the marine terminal, or even if the marine terminal is subject to control requirements.

Fugitive leaks from non vapor-tight vessels are not only a problem during loading and unloading, but result in emissions throughout the transport trip made by the vessel. If EPA does not feel it is appropriate to include such a standard under this rulemaking, organic liquid/vapor cargo tanks (marine or otherwise) should be listed as a source category under 112(k) and vapor-tightness standards should be established.

6. **Subcategory for Valdez Marine Terminal-** The District strongly opposes the proposed subcategorization. Ozone attainment status is relevant only for the RACT portion of the standard. The MACT requirements apply to all sources in the source category regardless of the attainment status of the area in which they are located. This is true of the entire program under Section 112, because the concern is not ozone, it is Hazardous Air Pollutants. VMT should be subject to the MACT standard with all other major source marine terminals.

7. **Ballasting-** This District supports the prohibition on ballasting. We have a similar prohibition in the Bay Area addressing the ballasting into unpurged cargo tanks.

8. **Inspection & Maintenance-** Frequent inspection and maintenance has been shown to have a substantial impact on the level of fugitive emissions from sources. In the Bay Area, marine cargo tanks must undergo vapor-tightness testing at least once every six months. We encourage EPA to require frequent inspection and maintenance of cargo vessels, and also of transfer equipment that is part of the marine terminal.

9. **Biasing of vapor tightness test results-** The Source Test Section at the District has reviewed the proposed test methods. Staff conclude that the proposed pressure-test procedure may bias the results towards compliance. The procedure permits the use of air to pressurize the vessel during testing. The presence of oxygen can result in vapor growth, and the test results would indicate an absence of leaks when, in fact, leaks are present. The use of inert gas to pressurize the cargo tank would minimize the bias, providing the vessel is equipped with an inert gas system, or could be cost-effectively retrofitted with one. If an inert gas system is not feasible, the volumetric flowrate of the leak could be quantified by measuring the flowrate of air which is required to maintain a specified pressure; EPA would need to establish a standard for an allowable leak rate at a given pressure. There should be no cargo in the tank during testing, and the headspace temperature should be monitored and recorded, to allow for correction due to thermal expansion. This method also has the benefit of providing a means of calculating fugitive emissions during loading. Fugitive emissions would be equal to the concentration times the flowrate, integrated over the loading event.

10. **Comments on Performance Test requirements-** The proposal requires that the performance be conducted to include the last 20 percent of the loading event. This is because a greater mass of VOC is displaced during the last twenty percent of loading. We are concerned, however, because the rule does not specify the time

period over which compliance must be determined; is it the average reduction efficiency over the entire test, or the average reduction efficiency during the last twenty percent? It is quite possible that a reduction device will have an average efficiency that exceeds 98% for the duration of a test conducted over the last 60% of loading, but that the efficiency during the last 20% of loading will be below 98%. The rule should specify the period for which compliance is to be determined.

11. **Comments on Method 25A-** The District is concerned that Method 25A will not be able to quantify VOC emissions; it quantifies emissions of TOC. The distinction is very important when testing thermal oxidation systems, because the USCG requires the inlet air to vapor stream ratio to exceed 1.5 times the upper explosive limit (for safety reasons). This is normally accomplished using natural gas injection. For example, a Bay Area facility injects approximately 720 cfm of natural gas during loading. We recommend using Method 25 to speciate methane, or that a carbon scrubber be used with Method 25A to allow the determination of VOC by subtraction.

12. **HAP emission calculation-** It is inappropriate to assume that the average control efficiency of the abatement device is representative of the reduction that will be achieved for all HAPs. Carbon adsorption will achieve a higher control efficiency for polar molecules with a high molecular weight. Incineration of certain HAPs will give rise to secondary HAP emissions (polycyclics, for example). Refrigeration has different efficiencies for specific compounds. HAP reduction should be established during the initial compliance test for the individual control unit, using Method 25 or an alternate speciating procedure.

13. **Regulatory alternatives impact analysis-** The review of costs, outputs, and employment impacts for affected products did not consider companies that offer portable vapor recovery units for use on tankers or barges that are not equipped with vapor recovery systems. Such companies require no capital investment on the part of the terminal, and may be feasible for terminals that load sporadically, or to help delay the capital outlay associated with purchasing equipment.

Photograph of the Chevron Richmond Long Wharf

Chevron Richmond Long Wharf - A MOTEMS Journey

October 2014

Karen Boven, P.G.
Chevron Project Manager

Photograph of the Phillips 66 Rodeo Terminal


Phillips 66 Rodeo, CA
Marine Terminal

U.S. Coast Guard Regulations: Marine Vapor Control Systems

(33 C.F.R. Part 154, Subpart P)

Detonation arrester means a device that is acceptable to the Commandant and includes a detonation arrester that is designed, built, and tested in accordance with Appendix A of this part or by another method acceptable to the Commandant for arresting flames and detonations.

Diluting means introducing a non-flammable, non-combustible, and non-reactive gas with the objective of reducing the hydrocarbon content of a vapor mixture to below the lower flammable limit so that it will not burn.

Drip leg means a section of piping that extends below piping grade to collect liquid passing through the vapor line and that has a diameter no more than the diameter of the pipe in which it is installed.

Elevated temperature means the temperature that exceeds 70 percent of the auto-ignition temperature, in degrees Celsius, of the vapors being collected.

Enriching means introducing a flammable gas with the objective of raising the hydrocarbon content of a vapor mixture above the upper flammable limit so that it will not burn.

Existing vapor control system means a vapor control system that satisfies the requirements of 33 CFR part 154, subpart E as certified by a certifying entity, or a tank barge cleaning facility vapor control system that meets the safety Standards of Navigation and Vessel Inspection Circular No. 1–96 as certified by a certifying entity or approved by the U.S. Coast Guard, and that began operating prior to August 15, 2013.

Facility main vapor control system means a vapor control system that primarily serves facility processing areas unrelated to tank vessel operations, such as the plant process, tank storage areas, or tank truck or railcar loading areas.

Facility operations manual means the manual required by 33 CFR 154.300, the contents of which are described in 33 CFR 154.310.

Facility vapor connection means the point in a facility's vapor collection system where it connects to a vapor collection hose or the base of a vapor collection arm and is located at the dock as close as possible to the tank vessel to minimize the length of the flexible vapor collection hose, thus reducing the hazards associated with the hose.

Fail-safe means a piece of equipment or instrument that is designed such that if any element should fail, it would go to a safe condition.

Fixed stripping line means a pipe extending to the low point of each cargo tank, welded through the deck and terminating above the deck with a valve plugged at the open end.

Flame arrester means a device that is designed, built, and tested in accordance with ASTM F 1273 or UL 525 (both incorporated by reference, see 33 CFR 154.106) for use in end-of-line applications for arresting flames.

Flame screen means a fitted single screen of corrosion-resistant wire of at least 30–by–30 mesh, or two fitted screens, both of corrosion-resistant wire, of at least 20–by–20 mesh, spaced apart not fewer than 12.7 millimeters (0.5 inch) or more than 38.1 millimeters (1.5 inches).

Flammable liquid means any liquid that gives off flammable vapors (as determined by flashpoint from an open-cup tester, as used to test burning oils) at or below a temperature of 80°F, and includes Grades A, B, and C flammable liquids defined in 46 CFR 30.10–22.

(c) A VCS with a single facility vapor connection that receives vapor from a vessel with cargo tanks that are not inerted or are partially inerted, and processes it with a vapor recovery unit must—

(1) Have a detonation arrester located as close as practicable to the facility vapor connection. The total pipe length between the detonation arrester and the facility vapor connection must not exceed 18 meters (59.1 feet) and the vapor piping between the detonation arrester and the facility vapor connection must be protected from any potential internal or external ignition source; or

(2) Have an inerting, enriching, or diluting system that meets the requirements of 33 CFR 154.2107.

(d) A VCS with a single facility vapor connection that receives vapor from a vessel with cargo tanks that are not inerted or are partially inerted, and processes the vapor with a vapor destruction unit must—

(1) Have a detonation arrester located as close as practicable to the facility vapor connection. The total pipe length between the detonation arrester and the facility vapor connection must not exceed 18 meters (59.1 feet) and the vapor piping between the detonation arrester and the facility vapor connection must be protected from any potential internal or external ignition source; and

(2) Have an inerting, enriching, or diluting system that satisfies the requirements of 33 CFR 154.2107.

(e) A VCS with multiple facility vapor connections that receives vapor from vessels with cargo tanks that carry inerted, partially inerted, non-inerted, or combinations of inerted, partially inerted, and non-inerted cargoes, and processes them with a vapor recovery unit, must have a detonation arrester located as close as practicable to each facility vapor connection. The total pipe length between the detonation arrester and each facility vapor connection must not exceed 18 meters (59.1 feet) and the vapor piping between the detonation arrester and the facility vapor connection must be protected from any potential internal or external ignition source.

(f) A VCS with multiple facility vapor connections that receives only inerted cargo vapor from vessels and processes it with a vapor destruction unit must—

(1) Satisfy the requirements of paragraph (a)(1) of this section for each facility vapor connection and have a detonation arrester located as close as practicable to each facility vapor connection. The oxygen analyzer required by paragraph (a)(1) can be located 4 meters (13.1 feet) downstream of the detonation arrester. The total pipe length between the detonation arrester and each facility vapor connection must not exceed 18 meters (59.1 feet) and the vapor piping between the detonation arrester and the facility vapor connection must be protected from any potential internal or external ignition source; or

(2) Have an inerting, enriching, or diluting system that meets the requirements of 33 CFR 154.2107.

(g) A VCS with multiple facility vapor connections that receives vapor from vessels with non-inerted or partially inerted cargoes, and processes the vapor with a vapor destruction unit must—

33 C.F.R. § 154.2106

§ 154.2106 Detonation arresters installation.

Effective: August 15, 2013
Currentness

This section applies only to facilities collecting vapors of flammable, combustible, or non-high flash point liquid cargoes.

(a) Detonation arresters must be installed in accordance with the guidelines outlined in the arrester manufacturer's acceptance letter provided by the Coast Guard.

(b) On either side of a detonation arrester, line size expansions must be in a straight pipe run and must be no closer than 120 times the pipe's diameter from the detonation arrester unless the manufacturer has test data to show the expansion can be closer.

SOURCE: 55 FR 25428, June 21, 1990; 55 FR 36252, Sept. 4, 1990; 58 FR 7352, Feb. 5, 1993; USCG–1999–5151, 64 FR 67175, Dec. 1, 1999; 65 FR 10943, March 1, 2000; USCG–2003–14505, 68 FR 16953, April 8, 2003; USCG–2003–15404, 68 FR 37741, June 25, 2003; USCG–2004–18057, 69 FR 34926, June 23, 2004; USCG–1999–5150, 78 FR 42616, July 16, 2013; USCG–1999–5150, 78 FR 42618, July 16, 2013; 80 FR 54418, Sept. 10, 2015, unless otherwise noted.

AUTHORITY: 33 U.S.C. 1225, 1231, 1321(j)(1)(C), (j)(5), (j)(6), and (m)(2); sec. 2, E.O. 12777, 56 FR 54757; Department of Homeland Security Delegation No. 0170.1. Subpart F is also issued under 33 U.S.C. 2735. Vapor control recovery provisions of Subpart P are also issued under 42 U.S.C. 7511b(f)(2).

Current through April 5, 2018; 83 FR 14604.

33 C.F.R. § 154.2107

§ 154.2107 Inerting, enriching, and diluting systems.

Effective: August 15, 2013
Currentness

This section applies only to facilities that control vapors of flammable, combustible, or non-high flash point liquid cargoes.

(a) Before receiving cargo vapor, a vapor control system (VCS) that uses a gas for inerting, enriching, or diluting must be capable of inerting, enriching, or diluting the vapor collection system, at a minimum of two system volume exchanges of inerting, enriching, or diluting gas, downstream of the injection point.

(b) A VCS that uses an inerting, enriching, or diluting system must be equipped, except as permitted by 33 CFR 154.2105(a), with a gas injection and mixing arrangement located as close as practicable to the facility vapor connection and no closer than 10 meters (32.8 feet) upstream from the vapor processing unit or the vapor-moving device that is not protected by a detonation arrester required by 33 CFR 154.2108(b). The total pipe length between the arrangement and the facility vapor connection must not exceed 22 meters (72.2 feet). The arrangement must be such that it provides complete mixing of the gases within 20 pipe diameters of the injection point. The vapor piping between the arrangement and the facility vapor connection must be protected from any potential internal or external ignition source.

(c) A VCS that uses an inerting or enriching system may not be operated at a vacuum after the injection point unless—

(1) There are no vacuum relief valves or other devices that could allow air into the vapor collection system downstream of the injection point, and pipe connections are flanged, threaded, or welded so no air can leak into the VCS; or

(2) An additional analyzer is used to monitor the vapor concentration downstream of such device and a mechanism is provided to inject additional inerting or enriching gas.

(d) A VCS that uses analyzers to control the amount of inerting, enriching, or diluting gas injected into the vapor collection line must be equipped with at least two analyzers. The analyzers must be connected so that—

(3) Instead of a liquid seal as required by paragraph (b)(1) of this section, have the following:

(i) An anti-flashback burner accepted by the Commandant and installed at each burner within the vapor destruction unit; and

(ii) A differential pressure sensor that activates the quick-closing stop valves as required by paragraph (b)(2) of this section upon sensing a reverse flow condition.

(c) A vapor destruction unit must—

(1) Not be within 30 meters (98.8 feet) of any tank vessel berth or mooring at the facility;

(2) Have a detonation arrester fitted in the inlet vapor line; and

(3) Activate an alarm that satisfies the requirements of 33 CFR 154.2100(e) and shut down when a flame is detected on the detonation arrester.

(d) When a vapor destruction unit shuts down or has a flame-out condition, the vapor destruction unit control system must—

(1) Activate and close the quick-closing stop valves required by paragraph (b)(2) of this section;

(2) Close the remotely operated cargo vapor shutoff valve required by 33 CFR 154.2101(a); and

(3) Automatically shut down any vapor-moving devices installed in the VCS.

(e) If a liquid seal is installed at the inlet to a vapor destruction unit, then—

(1) The liquid used in the liquid seal must be compatible with the vapors being controlled;

(2) For partially or totally soluble cargoes that can polymerize in solution, there must be an adequate amount of inhibitor in the liquid seal;

(3) The liquid seal must be compatible with the design of the VCS and must not contribute to the flammability of the vapor stream; and

(4) The liquid seal must have a low-level alarm and a low-low level shutdown.

Appendix C

Similar Source Regulatory Information

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

April 5, 2018

OFFICE OF
AIR AND RADIATION

Ms. LeAnn Johnson Koch
Perkins Coie
700 13th Street, NW
Suite 600
Washington, D.C. 20005-3960

Re: Limetree Bay Terminals, St. Croix, U.S. Virgin Islands – Permitting Questions

Dear Ms. Johnson Koch:

This is in response to your February 1, 2018, letter to the U.S. Environmental Protection Agency's (EPA) Region 2 Office, in which you sought EPA's concurrence on three New Source Review (NSR) permitting questions pertaining to the Limetree Bay Terminals (LBT) facility in St. Croix, U.S. Virgin Islands (USVI). In your letter, you specifically asked whether EPA concurs with LBT that:

> (1) restarting some of the idled refinery units as part of the "MARPOL Project"[1] (to produce fuel compliant with the maritime sulfur regulations taking effect January 2020) will not result in the facility being viewed as a new stationary source under EPA's current so-called Reactivation Policy;
>
> (2) the MARPOL Project and another LBT project to produce Renewable Diesel Fuel are independent and should not be considered a single project for purposes of applicability under the Prevention of Significant Deterioration (PSD) regulations; and
>
> (3) the addition of a deeper water loading configuration (Single Point Mooring or SPM) should be considered a modification to an existing emissions unit (i.e., the dock system and associated loading terminal) and not a new emissions unit for the PSD applicability analysis.

In addition to the foregoing inquiries, you previously sought EPA guidance regarding when emission decreases from a project can be considered within the NSR applicability analysis.

[1] MARPOL is the International Convention for the Prevention of Pollution from Ships.

Based on EPA's review of your submitted analyses and supporting documents, we concur that: (1) restarting of the refinery's idled units for the MARPOL Project should not be treated as a new stationary source under the current Reactivation Policy; (2) the MARPOL Project and the Renewable Diesel Fuel Project are independent of each other and therefore separate projects for PSD applicability; and (3) constructing the SPM would be considered a modification to an existing emissions unit rather than a new emissions unit. Discussion on each of these issues is provided below, along with information to address your previous question regarding accounting of emission decreases within the NSR applicability analysis.

Restarting Refinery Units and the Current Reactivation Policy

The current policy on the reactivation of sources provides that a major stationary source that has been idled for 2 or more years is presumed to be permanently shut down. *See In the Matter of Monroe Electric Generating Plant Entergy Louisiana, Inc.*, Proposed Operating Permit, Petition No. 6-99-2 (June 11, 1999). That policy states that if a source is permanently shut down, upon reactivation it is considered a "new" stationary source for purposes of PSD review. Accordingly, PSD applicability would be based on the reactivated source's potential to emit.

Importantly, however, this 2-year presumption is rebuttable. EPA will not consider the shutdown to have been permanent upon the owner or operator of the source making a demonstration that, at the time of the shutdown, and continuously throughout the shutdown period, they intended to restart the facility. Among the factors that EPA in the past has considered in evaluating the owner or operator's intent are:

- Length of time the facility has been shut down and concrete plans for restart;
- Statements by the owner or operator of intent;
- The cause of the shutdown;
- Status of permits, including but not limited to Clean Air Act operating permits, acid rain permits and other required permits, and emission inventory;
- Maintenance and inspections during shutdown; and
- Time and capital needed to restart.

In evaluating these factors, no single factor is likely to be conclusive in determining intent. Instead, EPA generally has considered the totality of all such factors and the relevant supporting documentation in evaluating whether there was a continuous intent to restart the facility.[2]

In the case of LBT's facility in St. Croix, our review of the information you have submitted leads us to conclude that both LBT and HOVENSA displayed a continuous intent to restart the refinery operations. Therefore, applying the criteria of the current Reactivation Policy, we have determined that LBT's St. Croix facility was not permanently shut down and should not be considered a "new source" for purposes of PSD applicability.

[2] As this description indicates, the current Reactivation Policy has been derived from a series of EPA site-specific determinations and guidance issued over the course of many years. Further, EPA has not cited any specific regulatory provisions of the NSR program to support its position on source "reactivation." We are applying the current Reactivation Policy to resolve the LBT issue, but we intend to reconsider the policy in the near future.

LBT's facility in St. Croix was previously owned by HOVENSA until 2016, at which time LBT purchased the refinery and terminal operations. As LBT explains, an economic downturn caused HOVENSA to idle the refinery operations in 2012. Nevertheless, since that time, the terminal operations, wastewater treatment plant, and power generation have continued to operate at this location. Even before HOVENSA announced, on February 21, 2012, that it had completed the final idling of all refinery units, HOVENSA had informed the USVI government of its plans to retain its permits and implement maintenance procedures on their equipment so that it could restart the refinery. LBT represents that over the next several years, HOVENSA spent over $400 million to maintain the restart capability of the refinery operations, which included removing residual material from equipment, retaining control room operability, and conducting other process equipment mothballing activities.

LBT provided EPA with a timeline and supporting information that included evidence of this continuous intent by HOVENSA and LBT to restart the facility. The supporting information included company statements, press releases, and various correspondence from 2011 through 2017. LBT also confirmed that HOVENSA and LBT maintained all environmental permits in active status and submitted timely renewal applications. Further, LBT stated that these companies continued to comply with the Refinery MACT, NSPS Subpart J, and all of the applicable RCRA regulations while the refinery units were idled. LBT represents that the companies maintained critical refinery equipment, such as compressors, pumps, utilities, wastewater treatment units in working order and conducted multiple walkthrough inspections at the plant, activities that are necessary for a restart. In order to demonstrate that the maintenance activities were performed, LBT provided a list of critical equipment and the timeline of significant maintenance activities performed at the refinery. LBT also represents that neither it nor HOVENSA made any statements to any party or issued any press release indicating any intent *not* to restart the plant in the future.

Project Aggregation – Renewable Diesel Project and Refinery Restart (MARPOL Project)

The term "project aggregation" describes the process of grouping "nominally separate changes that are sufficiently related based on established criteria … into a single common project for the purpose of determining PSD applicability."[3] More specifically, the emissions of the nominally separate changes are combined for the purposes of determining whether a "significant emissions increase" – referred to as "Step 1" of the NSR applicability test – will occur from the project. EPA's project aggregation policy aims to ensure the proper permitting of modifications that involve multiple physical and/or operational changes. Where the projects at issue are more reasonably deemed to constitute a single project for purposes of NSR, a source will not be allowed to circumvent major NSR by seeking to permit the individual activities separately under minor source NSR.

[3] Letter from Stephen Page, Director, Office of Air Quality Planning and Standards, to David Isaacs, Vice President, Government Policy, Semiconductor Industry Association (August 26, 2011). (SIA Letter)

LBT plans to construct the Renewable Diesel Project and the MARPOL Project at the current plant site in late 2018. Given that these projects will begin close in time to one another, LBT has sought EPA's concurrence that these projects should not be aggregated (i.e., considered to be a single project) for the purposes of the PSD applicability analyses. LBT representatives have been clear in statements to EPA that, while they are pursuing the Renewable Diesel Project and the MARPOL projects concurrently, they are separate and distinct projects. Based upon EPA's review of all the information LBT provided, we concur that the two projects are independent of each other and, therefore, should not be aggregated for purposes of PSD applicability.

In analyzing whether the two LBT projects at issue here should be aggregated, we have followed our current policy on project aggregation, which takes into account indicia ofrelatedness among the individual actions at a source in order to determine whether the activities, in the aggregate, are one physical or operational change as those terms are used in the statute and regulations.[4] Our policy on aggregation outlines an approach relying upon case-specific factors (*e.g.*, timing, funding, and the company's own records) and the relationship between nominally separate changes.

As explained in your letter, the MARPOL Project involves restarting certain existing refinery units to process crude oil, heavy fuel oil, and petroleum intermediates into refined petroleum products. This project will involve restarting a crude unit, a reformer, two naphtha hydrotreating units, a coker unit, two distillate hydrotreating units, an isomerization unit, and two sulfur recovery plants. These units will be configured to produce low-sulfur fuels (i.e., gasoline, diesel, and fuel oil) and are scheduled to begin operation just before January 2020, when the relevant MARPOL amendments and EPA implementing regulations take effect. LBT represents that the economic viability of the MARPOL Project depends on the value generated from converting petroleum crude into refined petroleum products and market advantages that may exist due to an anticipated market shortfall of MARPOL-compliant marine fuel in 2020.

Your letter explains that the proposed Renewable Diesel project will convert vegetable, animal, and recycled cooking oils into renewable diesel fuel. This project involves building a feedstock pretreatment train and a new hydrogen unit to convert the oils into diesel compounds, and repurposing an existing hydrotreating unit (previously used for the hydrotreating of petroleum liquids) as the reactor for the conversion. LBT represents that the Renewable Diesel Project will produce fuel meeting the requirements of the Renewable Fuel Standard (RFS) and California's Low Carbon Fuel Standard (LCFS) programs, and that the fuel could be blended with transportation fuel sold in the United States to generate Renewable Identification Numbers (RINs) under the RFS as well as LCFS credits. Further, LBT suggests that the renewable diesel fuel may be eligible for a federal blender's tax credit. According to LBT, the economic viability of the Renewable Diesel Project depends heavily on the future value of converting vegetable, animal, and recycled cooking oils into renewable fuel, as well as the value of RINs, LCFS, and other tax credits. Significantly, none of these factors relate to the MARPOL project.

---

[4] While EPA issued a revised policy on project aggregation in 2009, the policy has been stayed and is currently under reconsideration by the Agency. *See* 74 FR 2376 (January 15, 2009), 74 FR 7193 (Feb. 13, 2009), 75 FR 27643 (May 18, 2010). *See* 75 FR 19570-71 (April 15, 2010) for a collection of memoranda that provide examples of EPA's current approach to project aggregation.

LBT has shown that each of these two projects is technically distinct and does not depend on the other in terms of decision-making and timing, interaction between units, the process technologies used, feedstocks involved, or products produced. LBT stated that the MARPOL Project will be fully self-contained as the selected units are inspected, reconditioned as needed, and restarted. More specifically, LBT maintains that the raw materials, piping, process equipment, and material transfer systems for each project will be completely unshared and independent of the other project. LBT represents that the construction of one project does not necessitate or otherwise influence the construction of the other project.

LBT has demonstrated to our satisfaction that the economic viability of each project stands on its own, such that the Renewable Diesel Project could proceed on its own financial merits, regardless of the future of the MARPOL Project, and vice versa. In particular, LBT noted the unique opportunity presented to timely and economically reconfigure the idled hydrotreating equipment and the current availability of renewable fuel and tax credits as proof of lack of economic dependency between the Renewable Diesel and MARPOL Projects. Each project's feasibility is based on its own set of incentives and market realities and does not depend on the other project going forward.

We note that the one thing that may be considered to be common to both projects is the potential for shared utilities. However, sharing utilities does not in and of itself mean that activities at a source are functionally or economically dependent on one another. Since both projects will produce fuel gas, the power and steam required to operate each project can be generated from fuel gas produced by either the renewable diesel unit or the MARPOL refining unit, and in some cases the projects may combust fuel oil, so neither project is dependent on the other project for steam or power generation. In addition, LBT stated that each project will rely on the existing wastewater treatment and water production facilities at the terminal. LBT maintains there is no appreciable cost benefit that the Renewable Diesel Project will receive by virtue of the MARPOL Project because the utilities are already in operation as part of the ongoing terminal operations.

Single Point Mooring – Modification to an Existing Emission Unit

LBT also seeks a determination that the addition of a single point mooring (SPM) project to its existing marine loading/unloading system should be considered a modification to an existing unit at the facility rather than a new unit pursuant to the PSD regulations. In your letter, you explain that the existing marine loading/unloading system consists ofeten marine docks, each of which can load and unload multiple petroleum products. According to LBT, the proposed SPM addition would "extend from the jetty on the seabed for approximately 5,800 feet to a Pipeline End Manifold" that would be connected to a buoy via a flexible hose, and the buoy would load/unload crude oil onto ships via two floating hoses.

Based on the information provided by LBT, EPA believes that the addition of the SPM is reasonably considered to be an extension of the existing marine loading terminal. Therefore, EPA concludes that the SPM should be treated as a modification of the existing marine terminal emissions unit.

The definition of "emissions unit" in the PSD regulations does not speak to how broadly or narrowly to consider the scope of an emissions unit at a stationary source, nor does it address how to treat a new emissions point, such as the SPM, that is added to an existing stationary source with existing emission units. The definition at 40 CFR §52.21 (b)(7) states:

> *Emissions unit* means any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric utility steam generating unit as defined in paragraph (b)(31) of this section. For purposes of this section, there are two types of emissions units as described in paragraphs (b)(7)(i) and (ii) of this section:
>
>> (i) A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated.
>>
>> (ii) An existing emissions unit is any emissions unit that does not meet the requirements in paragraph (b)(7)(i) of this section. A replacement unit, as defined in paragraph (b)(33) of this section, is an existing emissions unit.

This regulatory language can be reasonably interpreted to provide that multiple pieces of related process equipment (or emission points) comprise a single emissions unit.

Prior EPA determinations interpreting the PSD regulations provide specific guidance on this question. Those determinations illustrate that ascertaining the proper scope of an "emissions unit" often requires very case- and fact-intensive analyses. For instance, in a letter to the Semiconductor Industry Association, EPA confirmed that it was appropriate to treat an entire semiconductor fabrication building, or "fab," as one emissions unit.[5] EPA based this decision on the "interconnected nature of the 'tools' in the fab" and the systems that deliver materials and manage discharges. The letter also pointed out that fab units could be located in adjoining buildings if they are "physically connected, integrated, and operated" in a continuous and consolidated manner, and that it may be more appropriate to treat physically separated operations as a separate emissions unit. In that letter, EPA also referenced other determinations by EPA Regions, in which the Regional office provided rationale for why grouping related processes and equipment into a single emissions unit made sense given the circumstances.[6]

In analyzing the SPM project, we note that the existing marine terminal currently loads and unloads crude oil in addition to other petroleum products. Based on the information provided in LBT's recent permit application to the Virgin Islands Department of Planning and Natural Resources, the SPM will load and unload only crude oil. Since LBT is currently loading and

---

[5] SIA Letter.

[6] Letter from Judith M. Katz, Region III, U.S. EPA, to John M. Daniel, Director, Air Program Coordination, Commonwealth of Virginia, Department of Environmental Quality, (November 30, 2000); Letter from Douglas M Skie, Region VIII, U.S. EPA, to Brad Beckham, Director, Air Pollution Control Division, Colorado Department of Health (February 6, 1990).

unloading crude oil at the existing marine terminal, the proposed SPM would not change the nature of the pollutant-emitting activity occurring at the terminal. Furthermore, the SPM will be physically connected to the existing marine loading terminal by way of an underwater piping system and will be completely integrated with the loading and storage operations at the existing terminal. Consequently, the SPM and current marine terminal appear to share the same interconnectedness that EPA previously found persuasive in its analysis of semiconductor fabs, which supports treating LBT's proposed SPM and the existing terminal as a single emissions unit.

We also note that state agency permit actions have also reflected the flexibility within the definition of emissions unit. There are several examples of state permitting agencies treating multiple marine loading berths/docks as a single emissions unit in the context of Title V permits.[7] Thus, the treatment of multiple loading docks or berths as a single emissions unit is not unusual.

Finally, in other correspondence LBT has informed EPA that it will be installing a vapor capture and collection system at the existing marine terminal, although LBT has indicated the system will not be used to reduce emissions that occur while loading ships at the SPM. Instead, LBT has indicated it intends to comply with the submerged loading requirements[8] when the ships are loaded at the SPM, and that the control of emissions from the existing docks will help offset the emission increases from the operation of the SPM. We note that, in the context of the PSD program, a BACT determination for a major modification is focused on each emissions unit. However, this approach does not foreclose a determination that different emission points within an emissions unit can have distinct BACT requirements due to technical or economic feasibility or other factors considered under a BACT review. Consequently, for LBT to install a vapor recovery system at the existing loading berths and apply a different control strategy for the SPM emission point does not necessitate that the SPM be treated as a separate emissions unit under the PSD program. EPA views the proposed SPM and the new vapor control system as being part of the overall integrated loading/unloading operation at the terminal, and views this operation as an integrated emissions unit for PSD purposes.

Consideration of Emission Decreases from the Project

While not specifically raised in your February 1, 2018 letter, LBT previously asked EPA whether, under the NSR applicability procedures (e.g., 40 CFR §52.21(a)(2)), emission decreases may be taken into account when a "significant emissions increase" calculation of projects which involve only existing units is undertaken at Step 1 of the NSR applicability analysis. As you should be aware, EPA has recently clarified that emission decreases from a project are to be considered at Step 1. This applies not only to existing emission units for but all categories of projects. *See* Project Emissions Accounting Under the New Source Review Preconstruction Permitting Program (March 13, 2018).

[7] *See, e.g.*, Indiana Department of Environmental Management, Part 70 Operating Permit, BP Products North America, Inc. – Whiting Business Unit (December 14, 2006); Commonwealth of Virginia, Department of Environmental Quality, Federal Operating Permit, TransMontaigne Operating Company, L.P. – Norfolk Terminal (April 7, 2014). EPA is also aware of analogous non-marine loading activities, such as truck loading racks, being treated as a single emissions unit.

[8] 46 CFR 153.282.

Conclusion

EPA's responses contained within this letter are based on the information LBT has provided EPA through letters and emails pertaining to your permitting questions. Since EPA does not have emissions information and other specifics regarding your planned projects, EPA is not providing any final determination on the applicability of the PSD regulations to your projects. A final determination on PSD applicability will be made on the basis of the information provided in your application and supporting materials. Finally, nothing in this letter's discussion of PSD policies should be interpreted to reflect EPA's views on the applicability or requirements of any other programs, including the New Source Performance Standards and the National Emissions Standards for Hazardous Air Pollutants.

If you have any questions about this letter, please contact Anna Marie Wood in the Office of Air Quality Planning and Standards at (919) 541-3604 or wood.anna@epa.gov.

Sincerely,

William L. Wehrum
Assistant Administrator

cc: Alexander Dominguez
David Harlow
John Filippelli
Bill Harnett
Peter D. Lopez
Peter Tsirigotis
Anna Marie Wood

85533

USCG-00-6981-2

UNITED STATES DEPARTMENT OF TRANSPORTATION

LICENSE TO OWN, CONSTRUCT AND OPERATE

A DEEPWATER PORT ISSUED TO LOOP LLC

On January 17, 1977, the Secretary of Transportation of the United States of America (hereinafter the "Secretary") pursuant to the Deepwater Port Act of 1974 (Pub. L. 93-627) (hereinafter, as amended from time to time, the "Act"), offered to LOOP Inc., a Delaware corporation a license to own, construct and operate the Deepwater Port known as LOOP, off the shores of southern Louisiana. LOOP INC. accepted the license and constructed and operated the deepwater port. In 1996, with the approval of the Secretary, LOOP INC. reorganized and became LOOP LLC, a Delaware limited liability company (hereinafter the "Licensee"). In both 1984 and 1996, Congress amended the Act and in 1998, pursuant to Sections 4(b)(2) and 4(e)(1) of the Act, the Licensee petitioned for a review and amendment of the license. On the basis of the Act and the review undertaken by the Department of Transportation upon petition of the Licensee, the Secretary hereby issues to Licensee this amended and updated license to own, construct and operate the Deepwater Port known as LOOP, off the shores of southern Louisiana.

ARTICLE 1. General Obligations of Licensee.

The Licensee shall own, construct and operate the Deepwater Port and the pipeline, storage, and other deepwater port facilities of the Licensee (such facilities, together with the Deepwater Port, hereinafter the "Port Complex") in accordance with the Act, any regulations promulgated thereunder (hereinafter the "Regulations"), other applicable Federal laws and regulations, the applicable laws of the nearest adjacent coastal state, the conditions of this license and the Licensee's operations manual as the same may be amended and approved from time to time (the "Operations Manual").

ARTICLE 2. Term.

This license remains in effect unless suspended or revoked by the Secretary as provided herein, or until surrendered by the Licensee.

The obligations of the Licensee contained in this license (except the obligations under Articles 8 and 10 hereof) shall survive the expiration of the term of this license or any revocation, termination or suspension of the rights and privileges granted hereby and shall continue until the Licensee shall have been notified by the Secretary in writing that such obligations have been satisfied and discharged, or that satisfactory provision therefor has been made.

ARTICLE 3. Location and Design.

The Licensee is authorized to construct and emplace offshore platforms, mooring buoys, pipelines, and related offshore facilities comprising the Deepwater Port, at the locations shown on, and in accordance with, the charts and descriptions in the application for this license (the "Application") or the Operations Manual to the extent that such locations are on the Outer Continental Shelf, outside of the jurisdiction of the State of Louisiana.

The Licensee shall design, locate and construct facilities included in the Port Complex, including but not limited to storage facilities and onshore pipelines, substantially in accordance with the locations and descriptions set forth in the Application or the Operations Manual. In reviewing proposed amendments to the Operations Manual, the Coast Guard shall consider adverse environmental impacts, inconsistency with the conditions of this license, and applicable engineering and safety codes and impacts upon efficiency.

This license does not convey any rights or interests or any exclusive privileges, except as expressly set forth herein in respect of lands on the Outer Continental Shelf, in or to real property, whether by title, easement, or otherwise, and it does not authorize any infringement of applicable Federal, State, or local laws or regulations, or the property rights of any person.

ARTICLE 4. Construction.

All work in the construction of any expansion or modification of the Port Complex shall be undertaken in a manner that does not interfere with the reasonable use of the high seas, adversely affect the safety of navigation, or pose a threat to human safety or health or to the environment.

Construction of the Port Complex shall not commence until the Licensee shall have submitted a quality assurance program for approval of the Coast Guard, and such approval shall have been received. The program shall include provision for inspection, testing or other procedures with respect to any component fabricated or material ordered prior to the approval and implementation of the quality assurance program.

The Licensee shall submit to inspection of the construction, operation and maintenance of the Port Complex at any time by the Commandant or his designate and by other Federal officials pursuant to their responsibilities under Federal law. The Licensee shall cooperate fully with all Federal inspection personnel and shall furnish them such access, facilities information, notice and services as they reasonably may require in the performance of their responsibilities. All facilities and services provided to Federal inspection personnel shall be equal in quality to that provided to the Licensee's representatives.

During the construction of any expansion or modification of the Port Complex the Licensee shall make office space available for inspection personnel at all construction and fabrication sites and shall provide subsistence, quarters, transportation and voice communications to shore for persons conducting inspections at offshore sites.

ARTICLE 5. Operations.

The Licensee shall operate the Port Complex at all times (a) without unreasonable interference with international navigation or other reasonable uses of the high seas and (b) in accordance with the Port Operations Manual approved in accordance with the Regulations.

ARTICLE 6. Environmental Protection.

The Licensee shall keep informed about procedures and equipment suitable for minimizing adverse effects on the marine environment and shall from time to time procure and employ the best available technology for such purposes.

ARTICLE 7. Financial Responsibility.

The Licensee has and shall have in effect guaranties approved by the Secretary (any such guaranty, hereinafter a "Guaranty"), of its obligations under Articles 4 and 17 hereof by parties which the Secretary has determined are financially capable of performing such obligations and meeting such liability.

Each Guaranty provides for several liability of the guarantor for the obligations of the Licensee under Articles 4 and 17 of this license, is enforceable by any party having a claim against the Licensee under said provisions and provides for regular reports to the Secretary in respect of financial condition.

The Licensee shall not assign or grant to any person any right in a Guaranty or any rights thereunder, if such assignment or grant would make such Guaranty unavailable for the satisfaction of any claim against the Licensee under the obligations guaranteed by such Guaranty.

Licensee shall demonstrate financial responsibility under Section 1016 of the Oil

Pollution Act of 1990 (33 U.S.C. § 2716 (c)(2)) in accordance with the letters in Annex A, or in such other manner as the Office of the Secretary may hereafter provide. The Secretary may require or accept in addition to, or in lieu of, such statement of financial responsibility the following, or any combination thereof, for any of the obligations enumerated above: insurance policies, surety bonds, owner guarantees of the Licensee's financial obligations in proportion to each Owner's respective interest in the Licensee; the cash deficiency provisions in a throughput and deficiency agreement filed with the Secretary; qualification as self-insurer. In order to qualify as a self-insurer the Licensee shall be required to maintain in the United States net worth in the amount for which such qualification is sought.

ARTICLE 8. Vessels, Shipments, Nondiscrimination & Rates.

In order to comply with its obligations under Section 8 of the Act, and subject to the conditions stated in its Operations Manual and its Terms and Conditions of Service, the Licensee shall furnish all facilities and services necessary and appropriate for the mooring of, unloading oil cargoes from, and otherwise handling and accommodating (but not fueling, manning or victualing, unless the Licensee shall so elect), all vessels that may reasonably be expected to utilize the facilities of the Deepwater Port, giving consideration to the availability of alternative domestic onshore facilities and the environmental and navigational risks associated with the use of such alternative facilities; provided, however, that the Licensee shall not be required to moor and accept cargoes from any vessel that, by reason of unique characteristics, cannot be accommodated at the Deepwater Port without undue expense or hazard.

ARTICLE 9. Expansion.

The Licensee may expand the Port Complex to an average daily throughput capacity of up to 4,250,000 barrels.

ARTICLE 10. Inland Transportation.

The Licensee shall establish with such common carrier pipelines as are owned or controlled by the Owners of the Licensee and their affiliates, or any of them, fair and adequate arrangements as may be reasonably required for the transportation of oil from the Port Complex to inland points served by such pipelines. Any requirements in such arrangements for minimum tender, shipment specification, or other conditions of shipment shall not be more restrictive than the conditions of shipment for the Port Complex, except such requirements that may be justified by pre-existing physical limitations of connecting facilities which cannot be readily corrected without substantial investment. The arrangements shall include a requirement that policies and practices concerning acceptance of cargoes when tenders exceed capacity shall be consistent with the policies and practices of the Port Complex. If any such common carrier pipeline fails or refuses to accept a shipment or any part thereof when properly tendered, the Licensee shall store such shipment or part without penalty until it shall have been accepted by such carrier.

Any pipeline constructed or extended after the date of issuance hereof, owned or controlled by the Owners or affiliates, or any of them, which will or reasonably could provide a connection between the Port Complex and any common carrier pipeline, shall (a) be owned by a single entity which shall operate such pipeline as a common carrier under the Interstate Commerce Act, (b) provide for terminal tankage on a common warehouse basis, and (c) participate in joint arrangements and conduct operations in a manner consistent with the provisions of the preceding paragraph.

The Licensee shall use its best efforts to establish similar arrangements with common carrier pipelines, not owned or controlled by Owners or affiliates, which will or reasonably could provide a connection with the Port Complex.

As used in this Article, the term "ownership" shall include, but not be limited to, ownership of any legal entity owning pipeline facilities and any joint interest in pipeline facilities. The term "control" shall mean actual or legal control, contractual control, control by ownership of the majority of the voting stock in a corporation owning pipeline facilities or ownership of the majority of joint interests in pipeline facilities. The term "affiliate" shall include any corporation or legal entity, controlled by, controlling, or under common control with the Licensee or any Owner.

ARTICLE 11. Hazard Prevention.

Notwithstanding any other provision of this license, the Licensee shall take all reasonable measures necessary to prevent hazards to human safety and health, property and to the environment that may arise from any activity concerning the construction, operation, maintenance, or termination of all or any part of the Port Complex.

ARTICLE 12. Indemnification.

The Licensee shall indemnify the Secretary, the United States of America, the State of Louisiana and its or their agents and employees (the “Indemnified Parties”), for, and hold them harmless from, any demand, claim, or cause of action, including but not limited to any demand, claim or cause of action for loss or damage to property or personal injury or death to persons caused by or resulting from any operation, act or omission at the Port Complex conducted by or on behalf of the Licensee. However, the Licensee shall not be held responsible to the Indemnified Parties under this section for any loss, damage, injury or death caused by or resulting from:

(a) negligence of an Indemnified Party other than the commission or omission of a discretionary function or duty on the party of a Federal Agency whether or not the discretion involved is abused; or

(b) the Licensee's non-negligent compliance with an order or directive of an Indemnified Party.

ARTICLE 13. Transferability; Ownership Interests.

Neither this license nor any right or privilege afforded hereby, nor any ownership interest in the Licensee shall be assigned or transferred by the Licensee without the consent of the Secretary.

ARTICLE 14. Equal Opportunity.

The Licensee shall take affirmative action to:

(a) ensure that no person shall on the ground of race, color, religion, sex or national origin be excluded from participation in, or denied the benefits of, or be subjected to discrimination under any activity conducted under the license;

(b) ensure that the employment practices and policies of the Licensee, its contractors and their subcontractors, regardless of tier, performing work or providing materials, services or supplies in connection with or for the ownership, construction or operation of the Port Complex, shall not discriminate against any person because of race, color, religion, sex or national origin; and

(c) ensure that business opportunities, including contracts and subcontracts for construction, materials, supplies or services shall be advertised and awarded in a manner designed to ensure reasonable and significant participation in such opportunities in a nondiscriminatory manner.

The Licensee shall develop and submit to the Secretary for his approval, within six months after the effective date of this license, a written affirmative action program to ensure that persons and businesses are not discriminated against because of race, color, religion, sex or national origin in activities conducted under the license, and that minorities and minority businesses receive a fair proportion of employment and contractual opportunities which will result from such activities.

The Licensee shall take the action necessary to implement the affirmative action program as approved by the Secretary.

ARTICLE 15. Conformance of Corporate Documents.

The Licensee and the Owners shall not have, and shall not enter into or file with any government body any corporate document or agreement among themselves or with others inconsistent with the terms hereof.

ARTICLE 16. Cause for Suspension or Termination.

If, during the term of this license, one or more of the following events shall occur:

(a) the Licensee or any Owner shall fail to observe or perform any obligation or condition contained herein or in a Guaranty, and such failure shall continue after written notice from the Secretary specifying the failure and demanding that the same be remedied within the period specified in such notice, which shall be not less than 30 days unless a lesser period is necessary to protect public health or safety or to eliminate imminent and substantial danger to the environment; or

(b) any statement of the Licensee or any Owner or affiliate contained in the Application, or in any document submitted to the Secretary or the Commandant in connection with the Application or a request for approval thereunder, hereunder, or under the Regulations, shall contain a material misrepresentation or an omission of a material fact; or

(c) an unauthorized assignment or transfer of this license or any rights granted hereby or of any Guaranty; or

(d) there shall be filed by or against the Licensee, any Owner, or any guarantor of an Owner, a petition in bankruptcy or insolvency or for reorganization or for the appointment of a receiver or trustee of all or a portion of the Licensee's, or such Owner's or guarantor's property, or if the Licensee or any Owner or guarantor thereof makes an assignment for the benefit of creditors or takes advantage of any insolvency act, and, in the case of an involuntary proceeding, within sixty days after the initiation of the proceeding the Licensee or such Owner or guarantor fails to secure a discontinuance of the proceeding, unless in the case of an Owner or guarantor, the Licensee shall have procured a Guaranty satisfactory to the Secretary of the obligations of such Owner or guarantor; or

(e) the Licensee shall have discontinued operating the Deepwater Port for a period of sixty days unless such failure is due to authorized construction activities or *force majeure*, or unless the Secretary shall have authorized such discontinuance; or

(f) the Licensee shall fail to comply with any order of a court of competent jurisdiction, or fail to satisfy a judgment, issued or arising out of a breach of any provision of this license, or any violation of the Act or Regulations; or

(g) the Licensee shall fail to comply with any compliance order issued by the Secretary, within the period set forth therein for compliance, and such compliance order shall not have been appealed pursuant to the provision of the then prevailing regulations in respect thereof or a final determination in respect of such an appeal shall have been made;

then, in any such case, the Secretary, at his option, may suspend or revoke this license or any right or privilege afforded the Licensee hereunder in accordance with the then prevailing regulations for suspension or revocation of licenses issued under the Act. Without limiting the foregoing, the Secretary may proceed (or request the Attorney General to proceed) by appropriate court action or actions either at law or in equity, to enforce performance by the Licensee or the Owners of the applicable provisions of this license or to recover damages for the breach thereof.

If the Secretary has reason to believe that the Licensee is not in compliance with Section 8 of the Act, the Secretary, in addition to the remedies described above in subparagraphs (a), (f), or (g), may commence an appropriate proceeding before the Federal Energy Regulatory Commission (or its successor agency) or request the Attorney General to take appropriate steps to enforce compliance with Section 8 and, when appropriate, to secure the imposition of appropriate sanctions. In addition, the Secretary may suspend or revoke this License if the Licensee is not complying with its obligations under Section 8 of the Act.

The remedies in this license provided in favor of the Licensor shall not be deemed exclusive but shall be cumulative and shall be in addition to all other remedies in its favor existing in the Act, the Regulations, and otherwise at law and in equity.

The failure of the Secretary to exercise his rights upon the occurrence of any of the contingencies set forth herein shall not constitute a waiver of any such right upon the continuation or recurrence of any such contingency, nor shall performance by the Secretary of the obligations of the Licensee constitute a waiver of any other right.

No action by the Secretary or the Attorney General for the enforcement of the terms hereof shall limit or restrict any right of a shipper or other person aggrieved by breach of the conditions and obligations of the Licensee contained herein, or by suspension or revocation of this license arising out of any such breach. The Licensee shall promptly notify all shippers of cargo and masters of vessels potentially affected by such suspension or revocation of the details, including the probable duration of a suspension, and shall take all precautions and use its best efforts to minimize inconvenience and expense to such shippers and masters.

ARTICLE 17. Removal.

Upon termination or revocation of this license, unless a petition for transfer is pending or has been approved, the Licensee shall remove all components of the Deepwater Port in accordance with plans approved by the Secretary. A plan for removal must be submitted by the Licensee to the Secretary within 30 days after the termination or revocation of this license. If the Licensee seeks a waiver of requirements to remove components as permitted by the Act, it may include such request in its removal plans. Removal must be completed within one year after the Licensee receives the Secretary's approval of the removal plans. If a petition for transfer of the license is pending, the obligation of the Licensee to take removal actions shall be suspended until the Secretary acts upon the transfer petition.

If the Licensee fails to remove any component of the Deepwater Port, the Secretary may arrange for its removal, and the Licensee shall be liable for the removal costs incurred.

ARTICLE 18. Enforcement; Delegation.

The rights, powers and authority of the Secretary hereunder may be enforced by the Attorney General or such other official of the United States of America having authority to enforce the provisions of the Act or having jurisdiction of the matters covered hereby or thereby.

The rights, powers and authority of the Secretary hereunder and under the Act and Regulations may be exercised and enforced by the Commandant and such agents or employees of the Department of Transportation and the Coast Guard to whom such rights, powers and authority may from time to time be delegated, whether generally by means of customary procedures of the Department of Transportation or specifically by delegation or appointment.

ARTICLE 19. Reports.

In addition to the reports required by the Regulations, the Licensee shall furnish such other information as the Commandant or the Secretary may reasonably request from time to time. The Licensee shall notify the Secretary of the pendency of any proceeding, order, or other judicial or administrative action concerning the activities covered hereby, and shall advise the Secretary from time to time of the status and results of any such action.

ARTICLE 20. Definitions.

Except as otherwise defined herein, the terms used in this license shall have the meanings specified in the Act.

ARTICLE 21. Limitations and Construction.

Except as expressly set forth in this license, no other license, authorization, permit or approval required by law is granted hereby. This license does not authorize anything that is or may be found to be in conflict with the Act, or the Regulations issued under the Act.

The approval of the Secretary or the Coast Guard of any design, construction method, or operating procedure, or any other approval granted by this license, shall not relieve the Licensee of liability that it may incur in the ownership, construction, or operation of the Deepwater Port.

ARTICLE 22. Responsibilities of Employees.

The Licensee shall cause its agents, employees, contractors and subcontractors to comply with all applicable provisions of this license.

ARTICLE 23. Notice.

Any notice required or permitted to be given by this license, the Act or the Regulations shall be deemed to have been given when delivered or when deposited in the United States mails, first-class postage prepaid, addressed as follows:

(a) if to the Secretary, to the Secretary of Transportation or to the Commandant of the Coast Guard at the United States Department of Transportation, Washington, D.C. 20590, unless required otherwise by regulation or another provision of this license;

(b) if to the Licensee, at One Seine Court, Suite 500, New Orleans, Louisiana 70114.

The Licensee shall notify the Secretary of any change in its address within five days of the change.

ARTICLE 24. Severability.

Each provision of this license is, and shall be deemed to be separate and independent of any other provision. If any provision of this license is held invalid or unenforceable or the operation thereof shall be suspended by order of a court of competent jurisdiction, the remainder of this license shall not be affected and shall be valid and enforced to the fullest extent permitted by law.

Any such invalidity or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

Washington, D.C.

Secretary of Transportation

Issued: June 1, 2000

AGREEMENT TO COMPLY

Pursuant to the provisions of section 4(e)(2) of the Deepwater Port Act of 1974, LOOP LLC hereby accepts the license to own, construct and operate a deepwater port, to which this agreement is attached, and in consideration thereof agrees to comply with and be bound by all conditions and provisions contained therein.

LOOP LLC

President

Dated: June 7, 2000,

ANNEX A:

FINANCIAL RESPONSIBILITY

Attachment (1): August 7, 1980 (William B. Johnston) letter from the Office of the Secretary of Transportation to John Oberdorfer, Esq. of Patton, Boggs & Blow.

Attachment (2): April 27, 1981 (J. Gordon Arbuckle) letter from Patton, Boggs & Blow to Ms. Judith T. Conner, Assistant Secretary for Policy and International Affairs, Department of Transportation.

OFFICE OF THE SECRETARY OF TRANSPORTATION
WASHINGTON, D.C. 20590

AUG 7 1980

John Oberdorfer, Esq.
Patton, Boggs & Blow
2550 M Street, N.W.
Washington, D.C. 20037

Dear John:

As a result of recent discussions, I believe we have reached agreement on what LOOP should submit to meet, in part through self-insurance, the requirement of section 18 of the Deepwater Port Act that the licensee "carry insurance or give evidence of other financial responsibility in an amount sufficient to meet the liabilities imposed" by the Act for damages (including cleanup costs) that result from discharge of oil from the port or from a vessel moored at the port, as well as Article 9 of the license. In your letters of November 29, 1979, and March 13, 1980, you put forth the proposal that LOOP would use a combination of an insurance policy, working capital, and net worth (including fixed assets) to satisfy the financial responsibility requirements. Based on this suggestion and your further conversations with the Department, we believe that a program which meets the following requirements would satisfy the license and statutory requirements.

(1) At the time it commences operations, LOOP shall have a combination of an effective paid up insurance policy covering claims against the licensee under section 18 of the Act and initial working capital of LOOP (calculated from the financial statements and reports that LOOP will submit to the Secretary under Item 4 below), as follows:

	If the insurance limits are */:	Then initial working capital required is at least:
(i)	$50 million per occurrence, and $75 million million annual aggregate	$25 million
(ii)	$100 million per occurrence, $150 million annual aggregate	$15 million
(iii)	$150 million per occurrence, $225 million annual aggregate	$10 million

*/ For policy limits and deductible levels other than those listed, LOOP is required to seek prior approval by the Secretary. For aggregate insurance limits between the amounts stated, the corresponding working capital requirement may be calculated by interpolation.

A policy written by OIL Insurance Limited (OIL), in substantially the same form as the policy dated Maarch 1980 (which was submitted to the Department on May 23, 1980), with a deductible not exceeding $5 million, shall be considered an appropriate policy for the purposes of this program, including the requirement of Items 1, 2, and 3.

(2) LOOP will, at all times, starting with the commencement of operations and ending when LOOP ceases to operate under the license, maintain as evidence of financial responsibility the following:

(a) Net worth of LOOP, calculated from the financial statements and reports that LOOP will submit to the Secretary under Item 4 below, of $50,000,000; and

(b) A combination of an effective, paid up insurance policy covering claims against the licensee under section 18 of the Act and working capital of LOOP (calculated from the financial statements and reports that LOOP will submit to the Secretary under Item 4 below) that satisfies Item 3 herein.

(3)(a) If at any time LOOP has knowledge that the sum of

(i) the net annual aggregate value of its OIL policy coverage, as defined in the last paragraph of this subsection plus

(ii) LOOP's working capital (in excess of an amount equal to the deductible on the annual OIL policy)

has fallen below $100 million, LOOP shall, within five days, bring such sum back to at least $100 million. This may be accomplished by procuring a supplemental insurance policy (which may include an increase in the increased occurrence and annual aggregate limit of the OIL policy; or a replacement policy to be approved by the Secretary) or, in the alternative, a letter of credit from a financially responsible entity, or a surety bond executed by a surety company which is certified by the United States Department of Treasury with respect to the issuance of federal bonds in the penal sum of the bond, the terms of which letter of credit, or surety bond allow funds to be used to meet liabilities under section 18, and shall notify the Secretary of such action. If a replacement of policy is procured, LOOP shall be considered in compliance with Item 2 during review and pending approval of such policy by the Secretary.

The net aggregate annual value of LOOP's oil policy coverage shall equal the policy's annual aggregate limit less--

(i) the amounts of all claims and expected claims against LOOP arising out of occurrences in the current policy year that would result in liability under section 18, whether or not such claims have been or shall be made by LOOP against the policy,

(ii) the amount of any other claims arising out of occurrences in the current policy year that LOOP has made against the policy, and

(iii) the amount of any net annual aggregate value of the OIL policy that is dedicated to fulfillment of Item 3(b).

(b) If, at the close of any quarterly reporting period, LOOP's net worth has fallen below the amount required by Item 2(a) above, and such deficiency shall not have been cured by the close of the quarterly reporting period ending six months after the close of the period within which the deficit first occurred, LOOP shall, within five days, remedy such deficiency. This may be accomplished by procuring in an amount equal to such deficiency a supplemental insurance policy (which may include dedication of any part of the net annual aggregate value of the OIL policy not required for purposes of Item 3(a); or an OIL policy of increased occurrence annual aggregate limits; or a replacement policy to be approved by the Secretary) or, in the alternative, a letter of credit from a financially responsible entity, or a surety bond executed by a surety company which is certified by the United States Department of the Treasury with respect to the issuance of federal bonds in the penal sum of the bond, the terms of which letter of credit or surety bond allow funds to be used to meet liabilities under section 18, and shall notify the Secretary of such action. If a replacement policy is procured, LOOP shall be considered in compliance with Item 3(b) during review and pending approval of such policy by the Secretary.

(4) LOOP will report to the Secretary in a manner similar to that described in the regulations of the Federal Maritime Commission governing self-insurance for Alaska pipeline oil pollution (46 C.F.R. 543.6(a)(3)(i)-(v)). In addition, for any period during which LOOP relies on an insurance policy to meet part of the financial responsibility requirement, LOOP's

reports shall include a statement (certified by an officer of LOOP) of the type and amount of such insurance, and of any changes made in the policy, and in any period in which LOOP relies on supplemental insurance, a letter of credit or a surety bond (as described in Item 3) a statement, similarly certified, or the type and amount of such insurance or letter of credit, or bond.

(5) LOOP shall provide the Department with the following assurances:

(a) That its previous statement that LOOP will not grant its creditors or any other person any right in LOOP's fixed assets that would be superior to the rights of any judgment creditor will continue in effect; and

(b) That LOOP will make its best efforts to assure the availability, within five days of its request, of the supplemental insurance policy, letter of credit, or surety bond, under the circumstances described in Item 3.

We believe that the proposal described is acceptable for LOOP's satisfaction of the terms of the license. Please let us know if this structure is acceptable to LOOP; we can then work out the details of reporting.

Sincerely

William B. Johnston

William B. Johnston
Assistant Secretary for Policy
and International Affairs

WASHINGTON, D. C. 20037

(202) 457-6000

CABLE: BARPAT
ITT TELEX: 440324
WU TELEX: 89-452
TELECOPIER: 457-6315

WRITER'S DIRECT DIAL

(202) 457-6090

April 27, 1981

HAND DELIVER

Ms. Judith T. Connor
Assistant Secretary for
Policy and International Affairs
Department of Transportation
400 7th Street, S.W.
Washington, D.C. 20590

Dear Ms. Connor:

In furtherance of Mr. William B. Johnston's letter to John Oberdorfer of August 7, 1980 ("the Johnston letter"), we are hereby submitting a statement of the procedures by which LOOP, Inc. will provide the Department of Transportation ("the Department") with information in fulfillment of LOOP's financial responsibility obligations under Section 18 of the Deepwater Port Act. The procedures, which are set forth below, are adapted from the Federal Maritime Commission regulatio governing self insurance for Alaska pipeline oil pollution. 46 C.F.R. § 543.6(a)(3)(i)-(v)(1980).

Two days prior to the date of receipt of first oil, LOOP will submit to the Department the following information:

(a) Copies of the annual nonconsolidated balance sheet and the annual nonconsolidated statement of income and surplus for the most recent fiscal year;

(b) An affidavit by the Corporate Treasurer indicating that, as of date first oil is received, LOOP's net worth and working capital will be at the levels required in the Johnston letter or that, in the alternative, letters of credit, in amounts sufficient to cure deficiencies will be in effect; and

(c) A copy of the current and effective insurance policy(ies) upon which LOOP is relying to meet its financial responsibility obligations, as well as any actual or anticipated claims against said policy(ies) as described at page 3 of the Johnston letter.

Thereafter, LOOP will submit the following information:

(1) Within three months after the close of a fiscal year, LOOP will submit an annual current balance sheet and an annual current statement of income and surplus for that fiscal year. LOOP's fiscal year now runs January 1 through December 31, hence these statements will be due on March 31. Each statement will be certified by an independent Certified Public Accountant.

To the extent that LOOP's net worth and working capital are not explicitly set forth in the statements, such information will be readily derivable by simple mathematical operations which will be explained in a letter accompanying them.

In the event that LOOP has assets outside the United States, the aforesaid statements will be accompanied by an additional statement from the accountant, certifying to the total amount of current assets which are located in the United States. The statements will be submitted in unconsolidated form unless LOOP notifies the Department otherwise at least sixty (60) days prior to the date for submission of the next report, in which case procedures will be established for the submission of additional information similar to that set forth in 46 C.F.R. § 453.6(a)(3)(i)(1980).

(2) A supplementary statement by an officer of LOOP who is also a Certified Public Accountant will be submitted certifying that, as of the end of the first six months of LOOP's fiscal year, its working capital and net worth have not fallen below the amounts required in the Johnston letter. This statement will be based upon the results of mid-year financial appraisal to be conducted by LOOP's in-house accountants and will be submitted within two months following the close of the six-month period, <u>i.e.</u>, by August 30.

(3) Supplemental affidavits by LOOP's Treasurer will be submitted stating that its working capital and net worth have not fallen below the required amounts as of the close of the first and third quarters of the fiscal year. These reports will be due within one month after the close of each quarter, <u>i.e.</u>, by April 30 and October 31, respectively.

✓ (4) With each report described in Items (1)-(3) above, LOOP will include a statement certified by an officer of LOOP of the type and amount of insurance upon which it is relying to meet its financial responsibility obligations. The statement will indicate the annual aggregate limit of LOOP's insurance coverage, the deductible level, and any actual or anticipated claims as described at page 3 of the Johnston letter.

(5) LOOP will notify the Department within one month following the renewal of the insurance coverage upon which it is relying to meet its financial responsibility obligations of the making of any substantive changes in such coverage.

✓ (6) With each quarterly report, LOOP will provide the Department with an affidavit by a corporate officer containing the assurances set forth in Item (5) of the Johnston letter.

(7) In any period in which LOOP relies on supplemental insurance, a letter of credit or a surety bond (as described in Item (3) of the Johnston letter), it will include a certified statement of same in the next quarterly report.

(8) In addition to the foregoing periodic reports, LOOP will provide the Secretary of Transportation with the notification required by Items (3)(a) and (b) of the Johnston letter. Such notification will be provided within five (5) business days of the date that LOOP knows or has reason to know that its working capital, net worth or insurance coverage have fallen below the required levels and will indicate that the deficiency has been cured in accordance with the Johnston letter.

(9) A report shall be deemed submitted when one (1) copy is delivered to the Department official whose name appears below or when it is sent by first class mail, postage pre-paid to:

Secretary
Department of Transportation
400 7th Street, S.W.
Washington, D.C. 20590

If a report is due on a Saturday, Sunday or Holiday, it will be due on the next business day.

We trust that you will find that the foregoing constitutes complete compliance with the reporting requirements contemplated by the Johnston letter. Please do not hesitate to contact us with any questions you might have.

Sincerely,

Gordon

J. Gordon Arbuckle

JGA/kjt

LOUISIANA OFFSHORE OIL PORT
OPERATIONS MANUAL
ADDENDUM

ENVIRONMENTAL PROTECTION

The Licensee shall implement in the design, construction, operation and maintenance of the Deepwater Port Complex measures described in the Application necessary to prevent, minimize or mitigate adverse environmental effects. The Licensee shall observe all special requirements set forth below and shall comply with all State laws, regulations and program requirements relating to environmental protection, land and water use, and coastal zone management.

The Licensee shall cooperate fully with Federal, State, and local agencies in the containment of, and mitigation of damage from, oil spills, whether or not arising out of operation of the Deepwater Port.

LOOP'S SPECIAL ENVIRONMENTAL REQUIREMENTS
(formerly contained in Annex A to the original license)

This section contains conditions to be made on the LOOP license to construct and operate a deepwater port off the coast of Louisiana. These conditions were developed in the process of the preparation of the environmental impact statement and the subsequent environmental review of the project. The authority of these conditions may be found in the Deepwater Port Act, Section 4(c)(1), 33 USC 1503 (e)(1), the Fish and Wildlife Coordination Act (16 USC 662), the Endangered Species Act (16 USC 1536), the Department of Transportation Act, Section 4(f) (49 USC 1653(f)), and the National Historic Preservation Act of 1966 (16 USC 470 et seq.) and its resulting regulations at 36 CFR 800. These conditions are also pursuant to and in furtherance of the Department of Transportation policy to "assure the protection, preservation, and enhancement of the nation's wetlands to the fullest extent practicable during the planning, construction, and operation of transportation facilities and projects." (DOT Order 5660.1 dated 21 May 1975).

(1) <u>Project Changes</u>
The Licensee must submit with any substantive proposed changes in the project or project plans an "Environmental Assessment" discussing the probable environmental consequences, adverse and beneficial, of the change. The "Environmental Assessment" shall be of a detail to a depth considered appropriate to the nature of the proposal.

(2) Brine Discharge Location
The Licensee shall sample the salt in the dome and the prospective leach water to determine their chemical compositions. He shall perform bioassay studies to determine more precisely the potential effects on marine life and habitats of the construction phase discharges and report the results of such studies and sampling to the U.S. Coast Guard. Following that determination, the Licensee shall perform similar studies to determine whether hydrocarbons or other contaminants may be expected to be entrained in the operating phase brines, and the extent to which the brines might harm indigenous sensitive marine organisms.

To form a more definitive basis for judgement of the relative merits of relocating the proposed brine discharge in deeper waters, a supplementary in situ sampling program shall be undertaken by the Licensee. Such a program would build on the data acquired by Nicholls State University in 1973 and 1974, with replicate benthic sampling in the vicinity of NSU Station 2 and along a reasonable (e.g., 5 mile) extension of the proposed pipeline bearing at several new stations, increasing in depth by three to five meter increments. The location of the brine diffuser could then be considered on the basis of combined knowledge or local benthic faunal organisms as determined by the aforementioned bioassays. Further, I am directing the Commandant to give special attention to oil/brine separator system technology for potential application to the LOOP facility.

(3) Use of Alternative Metals for Sacrificial Anodes
To further define and potentially mitigate the adverse impact potential of zinc sacrificial anodes the Licensee shall monitor zinc fate and effects in the project area and report the results to the U.S. Coast Guard. The results of this monitoring along with additional information on the reliability of alternative protection systems, will provide the basis for a later determination as to the anodic protection to be used for subsequent phases of LOOP.

(4) Offshore and Nearshore Pipelines
Since the offshore pipeline system is planned to be constructed in three steps (1980, 1981, and 1989), results of natural backfilling shall be closely monitored and reported to the U.S. Coast Guard by the Licensee after Phase I to ascertain its rate and extent. If results are favorable, Phase II could be carried out in a similar manner. If not, appropriate measures may be required (including importation of fill) to accomplish backfilling of the Phase I line as well as for subsequent phases.

At the discretion of the Commandant, the offshore pipelines shall be marked with buoys so long as they rest on the seabed prior to jetting into trenches, and also after jetting into trenches having a cover depth of 4 feet or less. Any buoys shall be removed when backfilling of the trenches has reached the top of the pipe.

In the surf zone and across the beach, special construction methods may be necessary to prevent undermining and displacement of the pipelines due to erosion of supporting soil, and to control surge flows through the pipeline trench.

(5) Pipeline Service and Access Roads

Where service and access roads traverse marsh areas, the Licensee shall use trestle-type structures, culverts, or other drainage systems at appropriate intervals in lieu of earth embankments, so as not to alter drainage patterns.

In order to prevent disturbance of the ground on account of unsuitable subgrade material, the Licensee shall give due consideration to constructing the roadway embankment upon filter fabric or similar material placed upon the undisturbed ground.

(6) Specific Measures to Minimize Harm to the Wisner State Wildlife Management Area and Other Wetlands

The Licensee shall construct spoil banks in such a manner to reduce the amount of spoil lost to runoff and to ensure retrieval of a maximum amount of spoil for backfilling of canals. Intermittent breaks shall be made in spoil banks by the Licensee to permit natural tidal flow past them.

The Licensee shall backfill to retrieve a maximum amount of spoil and restore spoil areas to surrounding elevations, and when appropriate, backfill shall be imported from an appropriate non-wetland source to ensure that a backfill deficit due to compaction, oxidation, runoff loss or other cause is made up and pipeline canals are completely filled in.

The Licensee shall construct permanent bulkheading wherever construction canals intersect other waterbodies to prevent saline intrustion along canals, backfilled or otherwise, across isohaline lines and shall construct, in backfilled canals, berms or other low backfill barriers at intervals along the canals to prevent advance across isohaline lines along the backfilled canals of sheetflow entering the canals. The Licensee shall maintain permanent bulkheads so their function is guaranteed.

The Licensee shall give consideration to marsh restoration in project impact areas.

The Licensee shall conduct appropriate and adequate monitoring to measure the short and long-term environmental impacts of the pipeline construction and to measure the effectiveness of any marsh restoration measures taken.

The Licensee shall take steps to restore to the control of the Louisiana Wildlife and Fisheries Commission an amount of comparable marshland equal in area to that removed from the Wisner Wildlife Management Area due to LOOP development.

(7) Specific Measures to Mitigate Adverse Impacts On, and to Preserve and Enhance Archaeological and Historical Sites

The following mitigative steps are to be taken by the Licensee to ensure the preservation and enhancement of archaeological sites and historical objects:

Clearly Mark Known Historical and Archaeological Sites

A qualified archaeologist shall clearly mark known historical and archaeological sites both during LOOP surveying activities and before construction is commenced. These sites shall be brought to the attention of key personnel engaged in construction so that the sites will not be inadvertently impacted. No heavy equipment or other impacting factor or activity shall be permitted within any site or in its immediate environs.

Notify State Historical Preservation Officer of Survey and Construction Activities

The State Historical Preservation Officer must be notified in advance and in a timely fashion of the time and place of surveying and construction in the vicinity of known sites. He must be permitted access to such sites during such activities to ensure that the sites are properly and clearly marked and that due caution is exercised in the conduct of such activities with regard to the sites.

Notification of Newly Discovered Archaeological and Historical Sites

The State Historic Preservation Officer and U.S. Coast Guard must be notified of the discovery of any previously unknown archaeological and historic sites during LOOP activities. All reasonable steps shall be taken to preserve the integrity of such sites. This may include, if necessary, the cessation of activities adversely affecting the sites until the State Historical Preservation Office and/or U.S. Coast Guard has had a reasonable opportunity to evaluate such sites and to recommend appropriate mitigative measures.

Conduct an Offshore Archaeological Survey and Report Detailed Results Before Construction Commences

An offshore archaeological survey, using methods approved by the State Historical Preservation Officer and the U.S. Coast Guard, must be conducted by the Licensee prior to the commencement of any offshore construction. Detailed results of the survey, including copies of appropriate charts, logs, tapes, films or other data forms, must be submitted by the Licensee to the State Historical Preservation Officer and the U.S. Coast Guard prior to commencement of any construction.

(8) Environmental Monitoring
The Licensee shall prepare a detailed environmental monitoring program plan and submit it to the U.S. Coast Guard. It should include provisions for periodic re-examination of the physical, chemical, and biological factors investigated during the baseline surveys contained in the LOOP Environmental Assessment and Baseline Study submitted with the license application. To be useful, intensive monitoring should commence shortly before project construction in the vicinity of the construction sites and potentially impacted areas and should continue through peak construction periods.

During project operations, a continuous monitoring program designed to ensure coverage of seasonal variations shall be undertaken. Of particular interest is the effect of any salinity changes at the reservoir or when brine storage capacity limitations require discharge into the Gulf of brine which has been in direct contact with crude oil. Measurements during all phases should focus on determining the extent of contaminants and effects in the ambient environment and through pathways of biological uptake.

(9) Phasing of Project Construction
Unless demonstrated to be infeasible or impracticable, the Licensee shall combine proposed separate pipeline construction efforts for the 36-inch brine disposal pipeline and the first 48-inch crude oil pipeline, and for all Phase I, II and III pipelines at major transportation route (e.g., the Intracoastal Waterway, Highway Louisiana 1, etc.) crossings, so as to lessen or mitigate the probable adverse environmental impacts associated with such construction.

84489

)EPARTMENT OF TRANSPORTATION

)ffice of the Secretary

;oast Guard

[USCG–2000–6981] — /

)eepwater Port License Amendments

\GENCY: The Office of the Secretary OST) and the United States Coast ;uard (USCG), DOT.

ACTION: Notice of change.

SUMMARY: The Secretary announces the issuance, effective June 7, 2000, of an amended and updated license to own, construct and operate the deepwater port known as LOOP (the Louisiana Offshore Oil Port, LLC) and of LOOP's operations manual addendum. The amended license and operating manual addendum respond to LOOP's April 29, 1998 petition to the Commandant for review and amendment of its license issued on January 17, 1977. The amendments and changes conform to legislative changes enacted over the past 20 years and more accurately reflect current operating conditions at the deepwater port.

The amended license and operations manual addendum and remarks by the Commandant and Office of the Secretary explaining the amendments may be viewed electronically through the Web Site for the Docket Management System at http://dms.dot.gov. and will be available for inspection or copying at room PL–401 on the Plaza Level of the Nassif Building at 400 Seventh Street SW, Washington, DC 20590 between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: Lieutenant Commander Russ Proctor, Ports & Facilities Compliance Division (G–MOC–3), U.S. Coast Guard Headquarters, 2100 Second Street SW., Washington, DC 20593–0001, telephone 202–267–0499, fax 202–267–0506, or Nancy R. Kessler, Senior Attorney-Advisor, Office of the Secretary, Office of Environmental, Civil Rights, and General Law (OST–C–10), U.S. Department of Transportation, 400 Seventh Street, SW., Washington, DC 20590, telephone 202–366–9301, fax 202–366–9170. For questions on viewing the license and operations manual addendum, call Dorothy Y. Beard, Chief, Dockets, Department of Transportation, telephone 202–366–5149.

SUPPLEMENTARY INFORMATION:

Background and Purpose

The Deepwater Port Act (33 U.S.C. 1501 *et seq.*) (Act), as amended by the Deepwater Port Act Amendments of 1984 (Pub. Law 98–419) and the Deepwater Port Modernization Act of 1996 (Pub. Law 104–324), authorizes the Secretary of Transportation to amend a deepwater port license on petition of a licensee. The Act directs the Secretary to review any condition of a deepwater port license to determine if the condition is uniform with conditions of other deepwater port licenses and whether it is reasonable and necessary to meet the objectives of the Act. The Act further directs the Secretary to amend or rescind any condition no longer necessary or otherwise required by any federal agency under the Act.

The Deepwater Port Act of 1974 established a comprehensive regulatory structure for the location, construction, and operation of deepwater ports to respond to environmental and safety concerns over the growing use of supertankers navigating coastal ports. On January 17, 1977, then Secretary of Transportation William T. Coleman, Jr. issued to LOOP a 20-year term license to own, construct and operate the deepwater port off the shores of southern Louisiana, pursuant to the Deepwater Port Act of 1974 ("the Act") (Pub. L. 93–627, 33 U.S.C. 1501 *et seq.*). On August 1, 1977, then Secretary of Transportation Brock Adams received LOOP's acceptance of the license. LOOP has since constructed and operated the nation's only deepwater port.

Since the passage of the 1974 Act, other methods of delivering oil to the United States, such as offshore lightering activities have provided significant market competition for LOOP. The Deepwater Port Act Amendments of 1984 (1984 Amendments) and the Deepwater Port Modernization Act of 1996 (1996 Modernization Act) responded to the competitive environment and removed unnecessary and burdensome requirements that hindered LOOP's economic viability.

The 1984 Amendments, for example, (1) simplified procedures for amendment, transfer, and reinstatement of a deepwater port license; (2) extended the term of a deepwater port license from 20 years to an indefinite period covering the life of the facility; and (3) relieved deepwater ports of economic regulation by the Federal Energy Regulatory Commission (while reserving future regulatory authority if appropriate competitive conditions no longer exist). The 1996 Modernization Act encouraged greater use of deepwater ports, particularly for Outer Continental Shelf oil; streamlined the deepwater port regulatory structure; and eliminated requirements for advance antitrust review (by the Department of Justice and Federal Trade Commission).

We have processed the license amendment through an informal, simplified administrative process, consistent with the changes made by the 1984 Amendments. The 1984 Amendments require only a "petition" for a license amendment, as distinguished from a formal, comprehensive "application" for license issuance. 33 U.S.C. 1502(4); 1503(b). We examined LOOP's license in light of the statutory direction that we review deepwater port license conditions to determine whether they are reasonable and necessary to meet the Act's objectives. 33 U.S.C. 1503(e)(1). Our changes, in response to LOOP's petition to amend its license, conform to the statutory requirement that we "amend or rescind any condition that is no longer necessary or otherwise required by any Federal department or agency" under the Act. 33 U.S.C. 1503(e)(1).

The Commandant, pursuant to delegated authority, processed LOOP's April 29, 1998, application for amendment of its license to construct and operate a deepwater port. 49 CFR part 1.46(s). I have the reserved authority to issue the amended license. 49 CFR part 1.44(o).

The license amendments eliminate: (1) The license term; (2) references to the original, outdated application; and (3) economic requirements (nondiscrimination, access for shipments, tariffs, required expansion) arising from the outdated common carrier obligation and from antitrust review that has been repealed. The amendments also: update the license to recognize completion of certain port construction; permit more flexible Coast Guard review of off-shore facilities; and transfer some operating procedures to the Operations Manual without eliminating any environmental protection provisions.

We have determined that the license amendments do not eliminate any environmental protection provisions. Certain conditions of the original license have been transferred verbatim to the addendum to LOOP's Operations Manual and the license conditions also require LOOP to operate the port in accordance with an approved Operations Manual. Both documents are binding sources of legal authority, and the environmental protections and enforcement procedures therefore have not changed. These changes conform to the 1996 Modernization Act requirement that, to the extent practicable, the deepwater port's operating procedures should be stated in an operations manual, approved by the Coast Guard, rather than in detailed and specific license conditions. 33 U.S.C. 1503(e)(1).

Accordingly, I have directed the **Federal Register** publication of the Amended License to Own, Construct and Operate a Deepwater Port issued to LOOP LLC.

Dated: June 1, 2000.

Rodney E. Slater,

Secretary of Transportation.

[FR Doc. 00–15282 Filed 6–15–00; 8:45 am]

BILLING CODE 4910–15–P; 4910–62–P

Appendix D

RBLC Search Results

Previous Page

Report Date: 06/06/2018 INDEX OF CONTROL TECHNOLOGIES DETERMINATIONS

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

Company Name	RBLC ID	Country	Permit Date(Est/Act)	Process Type	Process Description
PASADENA TERMINAL	TX-0825	USA	07/14/2017 ACT	42.010	Tank Truck Loading
				42.004	Marine Vessel Ship Loading
				42.004	Marine Barge Loading
				42.004	Uncaptured Marine Loading Fugitives From Ships
				42.004	Site-wide Equipment Piping Components
				42.005	Horizontal fixed roof storage tanks maintenance, start up, and shutdown
				42.005	Horizontal fixed roof storage tanks
				42.006	Internal floating roof storage tanks maintenance, startup, and shutdown
				49.006	Internal floating roof storage tanks
				42.010	Tank Truck Loading
				42.010	Tank Truck Unloading
				19.800	Fire Water Pump Engines
				19.390	Portable Flare
LYONDELL CHEMICAL BAYPORT CHOA	TX-0823	USA	06/07/2017 ACT	64.001	Reactor Furnaces
				64.003	Process Vents
				64.002	FUGITIVES
				64.004	STORAGE TANKS
				64.999	Emergency Diesel Engines
				64.999	COOLING TOWERS
				64.999	MSS
				64.999	FLARE
				64.005	LOADING
				64.004	STORAGE TANKS
FUEL OIL TERMINAL	TX-0818	USA	04/26/2017 ACT	42.004	FUGITIVES MARINE LOADING
				42.006	STORAGE TANKS MSS
				42.004	Marine Loading
				42.006	Storage Tanks
BIG ISLAND MINE & REFINERY	*WY-0078	USA	03/27/2017 ACT	90.017	Unit 7 Calciner
				90.017	DC-57 S1 and S2 Screens
				90.017	DC-95 Product Handling Rail Loadout
				90.017	Unit 4 Cooler/Classifier
				90.017	Dc-04 No. 2 Ore Shaft Headframe Area
				90.017	DC-08C Crusher Bldg Screens, 4C-36 and 4C-37A
				90.017	DC-09A Crusher Bldg, Housekeeping C-24, 4C-28 and 4C-29
				90.017	DC-37 No. 3 Shaft Ore Screening Bldg
				90.017	DC-52 Dust to DECA Transfer
				90.017	DC-53 Vacuum Truck Unloading
				90.017	DC-54 7C26 A to B Transfer
				90.017	Unit 6 Calciner
				90.017	DC-55 7C26 B to C Transfer
				90.017	DC-56 S4 Screens
				90.017	Unit 4 Dryer

MIDWEST FERTILIZER COMPANY LLC	IN-0263	USA	03/23/2017 ACT	19.390	FRONT END FLARE EU-017
				99.190	PAVED ROADS AND PARKING LOTS
				61.012	TRUCK AND RAIL LOADING OPERATION (EU-021A)
				19.390	BACK END FLARE (EU-018)
				13.310	STARTUP HEATER EU-002
				61.012	UREA SYNTHESIS PLANT (EU-006)
				61.012	UREA AMMONIUM NITRATE PLANT (EU-007)
				61.012	UREA GRANULATION UNIT (EU-008)
				62.014	NITRIC ACID PLANT (EU-009)
				99.999	EIGHTEEN CELL COOLING TOWER (EU-010)
				12.310	NATURAL GAS AUXILIARY BOILERS (EU-012A, EU-012B, EU-012C)
				17.110	EMERGENCY GENERATORS (EU014A AND EU-014B)
				19.390	AMMONIA STORAGE FLARE (EU-016)
CAMERON LNG FACILITY	LA-0316	USA	02/17/2017 ACT	17.110	emergency generator engines (6 units)
				15.110	Gas turbines (9 units)
				19.200	thermal oxidizers (4 units)
				50.007	fugitive emissions
				19.390	Flares (3 units)
				42.006	diesel tanks (2 units)
				42.006	condensate tanks (3 units)
				17.210	firewater pump engines (8 units)
				50.004	condensate loading
HOUSTON FUEL OIL TERMINAL	TX-0808	USA	09/02/2016 ACT	42.004	Fugitives at Marine Loading
				42.004	Marine Loading
				42.005	Storage Tank
				42.006	Storage Tanks
COMONIMER-1 UNIT	LA-0277	USA	09/01/2016 ACT	64.004	Storage Tanks (7 units)
				64.002	Fugitive Emissions
				64.004	Co-Catalyst Storage Vessel and Feed Drum
				64.005	Product Loading LR
				64.999	Devolatilization Vacuum Pump Separator D12-550
				64.004	C10+ Storage Tank T12-917
				64.999	Cooling Tower Y12-800
				64.999	Hopper, Dryer, Unloading, Water Tank
				64.999	Perimeter Ditch and Sump
				11.310	Utility Steam Boilers (3 units)
LAKE CHARLES CHEMICAL COMPLEX	LA-0319	USA	09/01/2016 ACT	11.310	steam boilers (b7-901, b7-902, b7-903)
				64.002	Fugitive Emissions FE-1
				64.004	Catalyst Drum/Vessel
				64.005	Product Loading LR
				64.004	storage tank t12-917
				64.999	perimeter ditch and sump - pds
				64.005	Raw Material Unloading
				64.004	Storage tanks (7 tanks)
				99.009	cooling tower y12-800
CORPUS CRUDE OIL TERMINAL	TX-0800	USA	06/22/2016 ACT	42.004	Marine Loading
				42.006	Storage Tanks
				42.004	Fugitives

				42.006	Floating Roof Storage Tanks - Controlled Maintenance, Startup and Shutdown (MSS)
BEAUMONT TERMINAL	TX-0799	USA	06/08/2016 ACT	42.010	Fugitives
				17.210	EMERGENCY ENGINES
				17.110	Fire pump engines
				42.005	Storage Tanks - fixed roof
				42.006	Storage Tanks - EFR
				42.006	Storage Tanks -IFR
				42.010	Truck and railcar loading
				42.010	Marine Loading
				42.006	Storage Tanks Floating Roof MSS
CORPUS CHRISTI TERMINAL	TX-0797	USA	05/04/2016 ACT	42.006	Petroleum Liquid Storage in Floating Roof Tanks
				42.999	Crude oil and condensate loading onto barges and ships.
				50.007	Petroleum Refining Equipment Leaks/Fugitive Emissions
BUCKEYE TERMINALS, LLC - HAMMO	IN-0248	USA	04/22/2016 ACT	42.004	RAILCAR LOADING RACK
HONEYWELL INTERNATIONAL, INC.	IN-0247	USA	04/21/2016 ACT	49.999	SOIL VAPOR EXTRACTION SYSTEM, TANK AND LOADING OPERATION
PORT ARTHUR LNG EXPORT TERMINA	TX-0790	USA	02/17/2016 ACT	50.006	LNG Export Acid Gas Recovery, Tanks & Loading
				50.999	LNG Export Facility - Natural Gas Fugitive Emissions
				42.999	LNG Export
				15.210	Simple Cycle Electrical Generation Gas Turbines 15.210
				15.210	Refrigeration Compression Turbines
LBC HOUSTON BAYPORT TERMINAL	TX-0783	USA	02/05/2016 ACT	99.999	Fugitives
				42.999	storage tank maintenance
				42.999	Storage Tanks
				42.009	Storage Tanks
				42.009	Marine Loading
COUNTRYMARK REFINING AND LOGIS	IN-0244	USA	12/03/2015 ACT	42.002	LOADING RACK
ALLIANCE REFINERY	LA-0284	USA	09/02/2015 ACT	50.007	Unit Fugitives for Loading Docks (406-FF, FUG 11)
				50.004	Product Dock No. 3 Non-MVR Loading (406-3, EQT 198)
				50.004	Product Dock No. 1 Non-MVR Loading (406-1, EQT 77)
				50.004	Product Dock No. 1 or 2 Marine Vapor Recovery Loading (406-D-16, EQT 76)
				50.004	Product Dock No. 1 or 2 Marine Vapor Recovery Loading (406-D-15, EQT 75)
				50.004	Product Dock No. 2 Non-MVR Loading (406-2, EQT 78)
MARATHON PETROLEUM COMPANY LP	IN-0243	USA	08/14/2015 ACT	42.002	LOADING RACK
CORPUS CHRISTI TERMINAL	TX-0760	USA	08/06/2015 ACT	50.007	Fugitives
				42.999	Marine loading of crude oil and condensate at NuStar Dock 16
COUNTRYMARK REFINING & LOGISTI	IN-0231	USA	06/30/2015 ACT	42.002	TRUCK LOADING RACK
INGLESIDE TERMINAL	TX-0752	USA	06/22/2015 ACT	42.006	Storage Tanks
				42.010	Loading
				42.010	Fugitives
				42.010	Tank Roof Landings
CCI CORPUS CHRISTI CONDENSATE	TX-0756	USA	06/19/2015 ACT	99.009	Cooling Tower
				22.200	Wastewater Treatment Plant
				50.005	Condensate Splitter - Process Equipment Shutdown and Clearing (MSS)

				42.006	Floating Roof Storage Tanks - Controlled Maintenance, Startup and Shutdown (MSS)
				42.004	Truck Loading
				42.004	Ship Loading
				42.004	Barge Loading
				50.009	Spent Caustic Tank, TK-4
				64.006	Wastewater Tank, TK-3
				42.005	Storage Tanks, TK-113, TK-114, and TK-115
				42.005	Storage Tanks, TK-110, TK-111, TK-112
				42.006	Storage Tanks, TK-107, TK-108, TK-109, 42.005
				42.006	Storage Tanks 116, TK-117, TK-118, and TK-119
				42.006	Storage Tanks, TK-105, TK-106
				42.006	Storage Tanks, TK-101, TK-102, TK-103, TK-104
				50.007	Fugitive Components
				50.005	Condensate Splitter
				15.210	Boilers, BL-1 and BL-2
				50.999	Charge Heaters, H-1 andH-2
				42.006	Storage Tanks, TK-120 and TK-121
KENAI NITROGEN OPERATIONS	AK-0083	USA	01/06/2015 ACT	19.310	Three (3) Flares
				99.110	2 Cell Cross-Flow Cooling Tower
				17.220	Gasoline Fired Fire Pump Engine
				62.999	Ammonia Plant, CO2 Vent
				62.999	H2 Vent
				61.012	Two (2) Urea Granulation Units
				42.009	Urea UF-85 Storage Tank
				42.009	Two (2) Methyl-diethanol Amine (MDEA) Storage Tanks
				99.110	Urea Ship Loading
				99.110	Urea Handling Units
				12.310	Startup Heater
				13.310	Five (5) Waste Heat Boilers
				12.310	Three (3) Package Boilers
				11.310	Primary Reformer Furnace
				16.110	Five (5) Natural Gas Fired Combustion Turbines
				17.210	Diesel Fired Well Pump
GEORGIA - PACIFIC BRETON, LLC	AL-0262	USA	06/11/2014 ACT	30.290	4a + 4b Truck unloading station
				30.290	3 Wood Chip Conveyers
				30.290	Chip Screening Building
MIDWEST FERTILIZER CORPORATION	IN-0173	USA	06/04/2014 ACT	17.210	RAW WATER PUMP
				17.210	FIRE PUMP
				99.140	FUGITIVE DUST FROM PAVED ROADS AND PARKING LOTS
				17.110	DIESEL FIRED EMERGENCY GENERATOR
				99.009	SIX CELL EVAPORATIVE COOLING TOWER
				99.009	TEN CELL EVAPORATIVE COOLING TOWER
				19.310	AMMONIA STORAGE FLARE
				19.310	BACK END FLARE
				19.310	FRONT END FLARE
				62.014	NITRIC ACID PLANT
				61.999	UREA JUNCTION OPERATION
				61.999	GRANULAR UAN RAIL LOADING OPERATION
				61.999	GRANULAR UAN TRUCK LOADOUT OPERATION

				64.002	FUGITIVE EMISSIONS FROM EQUIPMENT LEAKS
				61.999	UREA GRANULE STORAGE WAREHOUSE
				61.012	UREA GRANULATION UNIT
				61.012	CO2 PURIFICATION PROCESS
				16.210	THREE (3) AUXILARY BOILERS
				16.210	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES
				15.110	STARTUP HEATER
				11.310	REFORMER FURNACE
MIDWEST FERTILIZER CORPORATION	IN-0180	USA	06/04/2014 ACT	17.210	RAW WATER PUMP
				11.310	REFORMER FURNACE
				17.210	FIRE PUMP
				17.110	DIESEL FIRED EMERGENCY GENERATOR
				99.009	SIX CELL EVAPORATIVE COOLING TOWER
				99.009	TEN CELL EVAPORATIVE COOLING TOWER
				19.310	AMMONIA STORAGE FLARE
				19.310	BACK END FLARE
				19.310	FRONT END FLARE
				62.014	NITRIC ACID PLANT
				61.999	UREA JUNCTION OPERATION
				61.999	GRANULAR UAN RAIL LOADING OPERATION
				61.999	GRANULAR UAN TRUCK LOADOUT OPERATION
				64.002	FUGITIVE EMISSIONS FROM EQUIPMENT LEAKS
				61.999	UREA GRANULE STORAGE WAREHOUSE
				61.012	UREA GRANULATION UNIT
				61.012	CO2 PURIFICATION PROCESS
				16.210	THREE (3) AUXILARY BOILERS
				16.210	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES
				15.110	STARTUP HEATER
				99.140	FUGITIVE DUST FROM PAVED ROADS AND PARKING LOTS
ENID NITROGEN PLANT	OK-0162	USA	05/29/2014 ACT	11.310	Boiler
				11.310	Process Heaters (Existing)
				61.012	Reformer
				61.012	Cooling Towers
				61.012	Urea Granulator
				61.012	Solids Handling and Loading
				11.310	Reformer Heaters
LAKE CHARLES CHEMICAL COMPLEX	LA-0290	USA	05/23/2014 ACT	12.390	Hot Oil Heater (EQT 623)
				64.005	Loading Rack (EQT 624)
				64.002	LAB-2 Unit Fugitive Emissions (FUG 11)
				64.003	Process Vents
				64.004	Storage Tank NT-3 (EQT 626)
				64.004	Storage Tank NT-4 (EQT 627)
				64.004	Storage Tank NT-7 (EQT 628)
				64.004	Storage Tank NT-1 (EQT 625)
LAKE CHARLES CHEMICAL COMPLEX	LA-0291	USA	05/23/2014 ACT	64.004	GTLBO HN Grade Finished Product Tanks (EQT 795 & 796)
				64.004	FT50R Prover Tanks (EQT 703 & 704)
				64.004	FT50R Storage Tank (EQT 705)
				64.004	FT60R Prover Tanks (EQT 706 & 707)

64.004	FT60R Storage Tank (EQT 708)
64.004	FT70R Prover Tanks (EQT 709 & 710)
64.004	FT70R Storage Tank (EQT 711)
64.004	FT80R Prover Tanks (EQT 712 & 713)
64.004	FT50H Prover Tanks (EQT 714 & 715)
64.004	FT50H Storage Tank (EQT 716)
64.004	FT60H Prover Tanks (EQT 717 & 718)
64.004	FT60H Storage Tank (EQT 719)
64.004	FT70H Prover Tanks (EQT 720 & 721)
64.004	FT50HD Prover Tanks (EQT 722 & 723)
64.004	FT60HD Prover Tanks (EQT 724 & 725)
64.004	Wax Storage Tank (EQT 726)
64.004	Product Storage Tank (EQT 727)
64.004	Product Storage Tank (EQT 728)
64.004	Wax Storage Tank (EQT 729)
64.004	FT50 Non-Deoiled/Non HDT Wax Tank (EQT 741)
64.004	FT50 HDT and Deoiled Wax Tank (EQT 742)
64.004	FT50 HDT Deoiled Blended Wax Tank (EQT 743)
64.004	FT60 HDT and Deoiled Wax Tank (EQT 746)
64.004	FT50 Emulsion Wax Tank (EQT 744)
64.004	FT60 Non-Deoiled Wax Tank (EQT 745)
64.004	FT60 Blends Wax Tank (EQT 747)
64.004	FT70 Non-Deoiled/Non HDT Wax Tank (EQT 748)
64.004	FT70 HDT Wax Tank (EQT 749)
64.004	FT80 Non-Deoiled/Non HDT Wax Tank (EQT 750)
13.390	DW Reactor Feed Heaters (EQT 738 & 775)
64.999	Heat Exchangers
62.020	Sulfuric Acid Storage Tank (EQT 828)
64.005	Naphtha Berth 1 & 2 Loading (EQT 831 & 833)
64.004	Naphtha Storage Tanks (EQT 815, 816, & 817)
64.004	P/O Rundown Tanks (EQT 818, 819, 820, & 821)
64.004	Statutory Storage Tank (EQT 826)
64.004	Petroleum Wax Storage Tank (EQT 827)
64.004	Fresh Amine Storage Tank (EQT 829)
64.004	Process Licensor Methanol Tank Nos. 1 & 2 (EQT 797 & 798)
64.004	Storage Tanks Routed to Flare
99.999	High Temperature Paint Maintenance Activities (ACT 4)
64.005	Base Oils - Loading (EQT 835)
64.005	Diesel Berth 1 & 2 Loading (EQT 830 & 832)
64.002	GTL Unit Fugitive Emissions (FUG 15)
19.200	Vapor Combustor (EQT 834)
19.310	Multi-Point Ground Flares (EQT 836 & 837)
11.390	Process Heaters (EQT 690, 691, 692, 751, 752, & 753)
13.390	Process Heater (EQT 702)
13.390	Base Oils DW Reactor Feed Heater (EQT 776)
13.390	Base Oils Light Vacuum Feed Heater (EQT 777)
13.390	Base Oils Heavy Vacuum Feed Heater (EQT 778)
13.390	HC Reactor Feed Heaters (EQT 736 & 754)
12.390	Fractionator Feed Heaters (EQT 737 & 774)
64.003	Process Vents
64.004	GTLBO XLN Grade Finished Product Tanks (EQT 789 & 790)

				64.004	GTLBO LN Grade Finished Product Tanks (EQT 791 & 792)
				64.004	GTLBO MN Grade Finished Product Tanks (EQT 793 & 794)
LAKE CHARLES CHEMICAL COMPLEX	LA-0298	USA	05/23/2014 ACT	19.200	Guerbet Unit Thermal Oxidizer (EQT 771)
				13.390	Hot Oil Heater (EQT 772)
				64.999	High Pressure Flash Drum (EQT 920)
				64.003	Reactors
				64.999	Process Vents
				64.003	Distillation Towers
				64.999	Discharge Knock Out Drum (EQT 770)
				64.005	Guerbet Truck and Railcar Loading (EQT 769)
				64.002	Guerbet Fugitive Emissions (FUG 14)
				64.004	Guerbet Offspec Alcohol Storage Tanks (EQTs 766, 767, & 768)
				64.004	External Alcohol Product Storage Tank (EQT 765)
				64.004	Isofol 32 Storage Tank (EQT 764)
				64.004	Isofol 28 Storage Tank (EQT 763)
				64.004	Isofol 24 Storage Tank (EQT 762)
				64.004	Isofol 20 Storage Tank (EQT 761)
				64.004	Isofol 16 Storage Tank (EQT 760)
				64.004	Isofol 12 Storage Tank (EQT 759)
				64.003	Guerbet Reactor Overhead Condenser (EQT 928)
LAKE CHARLES CHEMICAL COMPLEX	LA-0299	USA	05/23/2014 ACT	64.999	Aqueous Byproduct Collector (EQT 1149)
				64.003	ETO 4 & ETO 5 HH Loop Reactors (EQT 1151 & 1152)
				64.999	Organic Byproduct Collector (EQT 1146)
				64.004	ETO4 & ETO5 Pre- and Post-Treatment Vessels (EQTs 1145, 1147, 1148, & 1150)
				64.999	Heat Exchangers
				64.005	Alcohol Loading Rack (EQT 1104)
				64.005	ETO Loading Rack (EQT 1103)
				64.004	Product Storage Tanks (EQTs 1101 & 1102)
				64.004	Novel Catalyst Drum (EQT 1100)
				64.004	#5 Utility Drum (EQT 1099)
				64.004	#4 Utility Drum (EQT 1098)
				64.004	#5 Alcohol Feed Drum (EQT 1097)
				64.004	#4 Alcohol Feed Drum (EQT 1096)
				64.004	Alcohol Storage Tanks (EQTs 1091, 1092, 1093, & 1094)
				64.004	#5 Product Drums (EQTs 1087, 1088, 1089, & 1090)
				64.004	#4 Product Drums (EQTs 1083, 1084, 1086, & 1086)
				64.004	#4 Product Storage Tanks (EQTs 1081 & 1082)
				64.002	Fugitives (FUG 21)
				64.004	Alcohol D150-911 (EQT 1095)
				19.310	ETO/Guerbet Elevated Flare (EQT 1079)
				19.310	ETO/Guerbet Vapor Combustion Unit II (EQT 1080)
LAKE CHARLES CHEMICAL COMPLEX	LA-0300	USA	05/23/2014 ACT	90.001	Alumina Slurry Tank (EQT 1006)
				90.001	Spray Dryer #4 Supersack Loading Baghouse (EQT 1007)
				90.001	Alumina Unit Fugitives (FUG 7)
				19.600	Spray Dryer #3 Dust Collector Vent Stack (EQT 1004)
				19.600	Spray Dryer #4 Dust Collector Vent Stack (EQT 1005)
				90.001	Spray Dryer #3, Silo Baghouses #1 & #2 (EQTs 1000 & 1001)
				90.001	Spray Dryer #4, Silo Baghouses #1 & #2 (EQTs 1002 & 1003)

LAKE CHARLES CHEMICAL COMPLEX	LA-0301	USA	05/23/2014 ACT	11.390	Utility Steam Boiler Nos. 1-3 (EQTs 967, 968, & 969)
				11.390	Furnace Nos. 1-8 (EQTs 971, 972, 973, 974, 975, 976, 977, & 978)
				19.200	Thermal Oxidizer (EQT 980)
				19.310	Elevated Flare (EQT 981)
				19.310	Ground Flare (EQT 982)
				17.210	Firewater Pump Nos. 1-3 (EQTs 997, 998, & 999)
				64.006	Benzene Stripper (EQT 1135)
				64.006	Wastewater Drums and Sumps
				64.006	Benzene Accumulator (EQT 1143)
				64.004	Pressurized Tanks
				64.004	LAC Tank (EQT 1110), Heavy Pygas (HAD) Tank (EQT 1111), and Pentane Drum (EQT 1113)
				64.004	Wash Oil Tank (EQT 1116) and Dimethyl Sulfide Tank (EQT 1117)
				64.006	Sulfide Caustic Oxidation (EQT 1136)
				64.003	C3 Hydrogenation Package (EQT 1127)
				64.003	Distillation Units
				64.006	Sour Water Stripper (EQT 1128)
				64.003	Caustic Wash Tower (EQT 1129) and Water Wash Tower (EQT 1132)
				64.003	C2 Hydrogenation Reactor (EQT 1126)
				64.003	Process Vents
				64.005	Loading Operations
				64.002	Steam Fugitive Emissions (FUG 17)
				99.009	Cooling Tower (EQT 979)
				64.006	Process Wastewater Treatment Plant (FUG 18)
				64.005	Railcar Loading (EQT 983)
				64.002	Fugitive Emissions (FUG 19)
				64.004	Methanol/Propanol Storage Tank (EQT 984)
				62.020	Sulfuric Acid Storage Tank (EQT 985)
				64.004	Methanol Storage Tank (EQT 986)
				64.006	Process Water Tanks (EQTs 987, 988, & 989)
				62.020	Sulfide Caustic Storage Tanks (EQTs 990, 991, & 992)
				64.004	Wash Oil Tank (EQT 993)
LAKE CHARLES CHEMICAL COMPLEX	LA-0302	USA	05/23/2014 ACT	64.999	Heat Exchangers
				62.020	Sulfuric Acid Storage Tank (EQT 1032)
				64.006	Cycle Water Treating Unit (EQT 1076)
				64.006	Wastewater VOC Stripper (Vent) (EQT 1072)
				64.004	EOM Storage Sphere (EQT 1078)
				64.003	Process Vents
				64.003	Process Vents
				13.390	Process Heat Boilers B-910A & B-910B (EQTs 1008 & 1009)
				19.310	Elevated Flare and Ground Flare (EQTs 1012 & 1013)
				99.009	Cooling Tower (EQT 1011)
				64.002	Fugitive Emissions (FUG 20)
				64.999	E-222 Regenerator Condenser CO2 Vent (EQT 1010)
				64.005	Railcar Loading (EQT 1014)
				64.004	MEG Storage Tanks (EQTs 1015, 1016, & 1017)
				64.004	DEG Storage Tanks (EQTs 1018 & 1019)
				64.004	TEG Storage Tanks (EQTs 1020 & 1021)
				64.004	DEG Storage Tank (EQT 1022)

				64.004	Crude Glycol Storage Tank (EQT 1023)
				64.004	Crude Heavy Glycol Storage Tank (EQT 1024)
				64.004	PEG Storage Tank (EQT 1025)
				64.004	MEG Rundown Storage Tanks (EQT 1026 & 1027)
				64.004	DEG Rundown Storage Tanks (EQT 1028 & 1029)
				64.004	TEG Rundown Storage Tanks (EQT 1030 & 1031)
				64.006	Glycol Sump (EQT 1075)
LAKE CHARLES CHEMICAL COMPLEX	LA-0303	USA	05/23/2014 ACT	64.006	Wastewater Collection and Transfer System (EQT 1203)
				64.003	S-5500 Vent Knockout Drum (EQT 1206)
				64.005	Alcohol Loading Rack (EQT 226)
				64.004	Melt Bin (EQT 1159)
				64.002	Fugitive Emissions (FUG 22)
				64.005	Loading Rack Operations (EQT 1162)
				64.004	Isopropanol/Slurry Tank (EQT 1163)
				64.004	Alcohol/Hydrolysis Condensate/Slurry Tanks (EQTs 1164, 1165, 1166, 1167, 1168, 1169, 1170, 1171, 1172, 1173, 1174, 1175, & 1176)
				64.004	Alcohol Utility Tower Product Tank (EQT 192)
				64.004	Hotwash Solvent Tank (EQT 149)
				64.004	Alcohol Utility Tower Product Tank (EQT 193)
				13.390	Reactor Feed Heater (EQT 1160)
				12.390	Hot Oil Heater (EQT 1161)
				19.310	Elevated Flare (EQT 133)
				19.310	Emission Combustion Unit #3 Ground Flare (EQT 500)
				64.999	Heat Exchangers
				64.004	Growth Product Tanks (EQTs 1177 & 1180)
				64.004	Growth Product Tanks (EQTs 1178 & 1179)
				64.004	Hydrolysis Water Storage Tank (EQT 1181)
				64.004	Wet Crude Alcohol Storage Tank (EQT 1182)
				64.004	HF 1000/LPA 140 Tank (EQT 1183)
				64.004	TPT/LPA 140 Tank (EQT 1184)
				64.004	C6 Alc A & B Tanks (EQTs 1185 & 1186)
				64.004	Light Pure Cut Tank (EQT 1187)
				64.004	C1214 Alcohol Tank (EQT 1188)
				64.004	C8 Pure Cut Tank (EQT 1189)
				64.004	C10 Pure Cut Tank (EQT 1190)
				64.004	C12 Pure Cut Tank (EQT 1191)
				64.004	C14 Pure Cut Tank (EQT 1192)
				64.004	C16 Pure Cut Tank (EQT 1193)
				64.004	C18 Pure Cut Tank (EQT 1194)
				64.004	C810 Alcohol Tank (EQT 1195)
				64.004	C1214 Alcohol Tank (EQT 1196)
				64.004	C1618 Alcohol Tank (EQT 1197)
				64.004	C20+ Alcohol Tank (EQT 1198)
				64.004	Alcohol/Butanol Tank (EQT 158)
				64.004	Alcohol Tanks (EQTs 159 & 165)
				64.004	Alcohol Tank (EQT 171)
				64.004	Alcohol Tank (EQT 174)
				64.004	Alcohol Tank (EQT 176)
				64.004	Alcohol Tank (EQT 182)
				64.004	Alcohol Storage Tank (EQT 188)

				64.004	Alcohol Storage Tank (EQT 189)
				64.004	Alkoxide Tank Service (EQT 205)
				64.004	Alcohol Tank (EQT 210)
				64.004	Alcohol Tank (EQT 213)
				64.003	ALEX Alkoxide Stripper Tower (EQT 1207)
				64.003	Reactor and Tower Process Vents
				64.003	ALEX Utility Tower (EQT 1217)
				64.004	SSO Storage Tank (EQT 139)
				64.004	Alcohol Tank (EQT 173)
G2G PLANT	*LA-0315	USA	05/23/2014 ACT	64.003	Steam Methane Reformer
				64.002	Wastewater System Fugitives
				11.310	Utility Boiler 2
				11.310	Utility Boiler 3
				13.310	Reactor Charge Heater - 53B001
				13.310	Regeneraton Heater - 51B001
				13.310	Recycle Gas Heater - 51B002A
				13.310	Recycle Gas Heater - 51B002B
				13.310	Recycle Gas Heater - 51B002C
				13.310	Recycle Gas Heater - 51B002D
				13.310	Recycle Gas Heater - 51B002E
				19.390	Flare Pilot Burner
				17.110	Emergency Diesel Generator 1
				17.110	Emergency Diesel Generator 2
				17.110	Fire Pump Diesel Engine 1
				17.110	Fire Pump Diesel Engine 2
				99.009	Cooling Tower
				64.004	Crude Methanol Storage Tank
				64.004	Methanol Day Shift Tank 1
				42.006	Gasoline Day Shift Tank 1
				42.006	Gasoline Day Shift Tank 2
				42.006	Product Gasoline Tank 1
				42.006	Product Gasoline Tank 2
				69.999	Methanol Degassing
				64.005	Methanol Loading
				64.999	Gasoline Degassing
				64.004	Methanol Day Shift Tank 2
				64.004	Product Methanol Tank
				42.999	Gasoline Loading
				64.002	Process Methanol Fugitives
				64.002	Process Gasoline Fugitives
				11.310	Utility Boiler 1
GAS TO GASOLINE PLANT	TX-0656	USA	05/16/2014 ACT	42.004	RAILCAR AND TRUCK LOADING
				42.005	Fixed Roof Tanks (3)
				13.310	heaters (5)
				13.310	Heaters
				42.002	GASOLINE STORAGE
				50.002	Reformer
				50.002	Cooling Tower
				64.002	Fugitive Components

				42.009	METHANOL AND WATER STORAGE TANK
				11.310	Boiler
BEAUMONT GAS TO GASOLINE PLANT	*TX-0657	USA	05/16/2014 ACT	50.002	Organic Material Storage
				50.002	Organic Material Storage
				50.002	Railcar and truck loading
				50.002	Fugitive emissions in Gas to Gasoline Plant
				50.002	cooling tower
				50.002	Catalyst Regeneration
				50.002	Gasoline Storage
				50.002	Gasoline Storage
				50.002	Gasoline Storage
				50.002	Railcar and Truck loading
				50.002	3 Fixed roof tanks
				50.002	Heater
				50.002	Wastewater processing and handling
				50.002	Boiler
				50.002	Reformer
				50.002	Heater
				50.002	5 Heaters
MAG PELLET LLC	IN-0185	USA	04/24/2014 ACT	90.021	IRON CONCENTRATE UNLOADING
				81.190	COKE BREEZE CONVEYANCE & STORAGE BIN
				90.009	BENTONITE UNLOADING (TRUCK) & STORAGE AREA
				90.019	LIMESTONE AND DOLOMITE GRINDING MILL BIN AREA
				90.021	MIXING AREA MATERIAL HANDLING SYSTEM
				90.021	HEARTH LAYER BIN SYSTEM
				90.021	MACHINE DISCHARGE SYSTEM
				90.021	HEARTH LAYER SEPARATION SYSTEM
				90.021	OXIDE PELLET STORAGE SYSTEM
				90.021	OXIDE PELLET LOADOUT SYSTEM
				90.021	DUST RECYCLE SURGE HOPPER & BLOW TANK AREA
				99.190	RECYCLED DUST STORAGE AREA
				90.021	IRON CONCENTRATE TRANSFER AND STORAGE AREA
				90.019	LIMESTONE UNLOADING & STORAGE AREA
				90.021	DOLOMITE UNLOADING & STORAGE AREA
				90.019	LIMESTONE/DOLOMITE HOPPER, BELT FEEDER & GRIZZLY FEEDER/SCREENER
				11.310	FURNACE HOOD EXHAUST
				11.310	FURNACE WINDBOX EXHAUST
				17.130	EMERGENCY GENERATORS
				17.110	DIESEL FIRE PUMP
				19.600	SPACE HEATERS AND LAB FURNACES
				19.600	COKE BREEZE ADDITIVE SYSTEM AIR HEATER
				19.600	LIMESTONE/DOLOMITE ADDITIVE SYSTEM AIR HEATER
				99.009	COOLING TOWERS
DIRECT REDUCED IRON AND HOT BR	TX-0725	USA	03/18/2014 ACT	81.900	Dock Ore Unloading
				81.900	Charge Hopper Dedusting
				81.900	Oxide Pellet Pile Transfer and Dedusting (Pre-Enclosure)
				81.900	Oxide Pellet Pile Transfer and Dedusting (Post-Enclosure)
				81.900	Briquetter Dedusting

				81.900	HBI Cooling Conveyor No. 1 and No. 2
				81.900	Transfer and Product Screening Station No. 1 (Pre-Pile)
				81.900	Transfer and Product Screening Station No. 2 (Post Pile)
				81.900	HBI Product Storage Piles
				81.900	Remet/Fines Storage
				81.900	Process Water Degasser
				81.900	Cooling Tower
				81.900	Oxide Unloading Bin and Dedusting
				81.900	Furnace Charge Hopper Loading Silos
				81.900	Oxide and Remet Screening and Dedusting
				81.900	Reactor Furnace
				81.900	Reducing Gas Preparation
ORGANIC CHEMICAL MANUFACTURING	TX-0722	USA	03/14/2014 ACT	50.999	Storage Tanks (Fixed Roof)
				50.999	Storage Tanks (IFR)
				50.999	Flare
				50.999	Fugitives
				50.999	Loading
				50.999	MSS
COLONIAL PIPELINE CO LINDEN JC	NJ-0083	USA	03/11/2014 ACT	42.006	26 Internal floating roof storage tanks for materials with RVP
				19.600	Transmix Processing Unit with gas-fired process heaters
				42.002	Light Products Loading Rack
EXXONMOBIL BATON ROUGE REFINER	LA-0274	USA	10/01/2013 ACT	50.999	SRLA/COCAP
				50.006	SRLA F-101 Incinerator
				50.004	SRLA Sulfur Truck Loading
				50.006	SRLA F-201 Incinerator
				50.999	SRLA TGCU T-301 Vent
				50.999	CAT/WGS Cat Complex Wet Gas Scrubber
CF INDUSTRIES NITROGEN, LLC -	IA-0106	USA	07/12/2013 ACT	61.012	Primary Reformer
				61.012	LP Offgases Absorber Vent
				61.012	Emergency Vents
				99.140	New Plant Haul Road
				64.002	VOC Emissions from Equipment Leaks
				99.009	Cooling Towers
				17.110	Emergency Generators
				42.009	Diesel Belly Tanks
				42.009	Methyl-diethanol Amine (MDEA) Storage Tank
				13.310	Startup Heater
				11.310	Boilers
				61.012	Flares
				61.012	Urea Granulator
				61.012	Carbon Dioxide Regenerator
				61.012	Condensate Steam Stripper
				61.012	Hydrogen Recovery Unit
				42.009	Urea Uf-85 Storage Tank
				61.012	Urea Loading
GALENA PARK TERMINAL	TX-0682	USA	06/12/2013 ACT	64.005	Loading
				19.900	Vapor Combustion Units
				42.009	Storage Tanks
				99.999	MSS-Heaters

				99.999	Fugitives
				12.310	Heaters
MAGNETATION LLC	IN-0167	USA	04/16/2013 ACT	17.230	FIRE WATER PUMP
				11.310	FURNACE WINDBOX EXHAUST (WBE)
				11.310	FURNACE HOOD EXHAUST
				90.021	HEARTH LAYER BIN SYSTEM
				90.021	MIXING AREA MATERIAL HANDLING SYSTEM
				19.600	GROUND LIMESTONE/DOLOMITE ADDITIVE SYSTEM AIR HEATER
				90.019	GROUND LIMESTONE/DOLOMITE ADDITIVE SYSTEM
				90.019	LIMESTONE/DOLOMITE GRINDING MILL BIN AREA
				90.019	LIMESTONE/DOLOMITE HOPPER, BELT FEEDER, GRIZZLY FEEDER/SCREENER
				81.190	COKE BREEZE ADDITIVE SYSTEM
				90.009	BENTONITE ADDITIVE SYSTEM
				99.120	SODA ASH UNLOADING STORAGE AREA
				99.999	ORGANIC BINDER UNLOADING & STORAGE AREA
				90.009	BENTONITE UNLOADING (TRUCK) & STORAGE AREA
				81.190	COKE BREEZE PNEUMATIC CONVEYANCE & STORAGE BIN
				81.190	COKE BREEZE UNLOADING (TRUCK)
				90.024	DOLOMITE CONVEYOR & ENCLOSED STORAGE (PILE)
				90.024	DOLOMITE UNLOADING (TRUCK)
				90.021	GREENBALL PRODUCTION SYSTEM
				90.021	IRON ORE WET GRINDING AND FILTER CAKE PRODUCTION
				17.130	EMERGENCY GENERATOR
				19.600	COKE BREEZE ADDITIVE SYSTEM AIR HEATER
				90.021	IRON CONCENTRATE UNLOADING AND STORAGE AREA
				90.021	IRON ORE CONCENTRATE TRANSFER AND SROAGE AREA
				90.019	LIMESTONE UNLOADING (TRUCK)
				90.019	LIMESTONE CONVEYOR & ENCLOSED STORAGE (PILE)
				90.021	PELLET HARDENING FURNACE
				90.021	FURNACE DISCHARGE SYSTEM
				99.009	COOLING TOWER
				90.021	HEARTH LAYER SEPERATION SYSTEM
				90.021	OXIDE PELLET STORAGE & UNLOADING SYSTEM
				90.019	WBE LIME STORAGE AREA
				90.021	WBE RESIDUAL PRODUCT LOADING AREA
				99.190	RECYCLED DUST STORAGE AREA
				19.600	SPACE HEATERS
AMMONIA PRODUCTION FACILITY	LA-0272	USA	03/27/2013 ACT	19.310	BACK END PROCESS FLARE (2204-B)
				19.310	FRONT END PROCESS FLARE (2203-B)
				11.390	PRIMARY REFORMER FURNACE (101-B)
				13.310	AMMONIA START-UP HEATER (102-B)
				62.999	CO2 STRIPPER VENT (102-E)
				19.310	RAIL LOADING FLARE (2205-B)
				99.009	COOLING TOWER (2101-U)
				12.310	COMMISSIONING BOILERS 1 & 2 (CB-1 & CB-2)
				17.110	EMERGENCY DIESEL GENERATOR (2205-B)
				42.009	AMDEA STORAGE TANK (2009-F)

				62.999	FUGITIVE EMISSIONS (FUG)
				19.310	AMMONIA STORAGE FLARE (2202-B)
ROSE VALLEY PLANT	OK-0153	USA	03/01/2013 ACT	17.130	EMERGENCY GENERATORS 2,889-HP CAT G3520C IM
				13.310	REGENERATION HEATERS
				50.999	CONDENSATE TRUCK LOADING
				50.002	AMINE UNITS - STILL VENT
				17.130	COMPRESSOR ENGINE 1,775-HP CAT G3606LE
				50.999	FUGITIVE EQUIPMENT
				13.310	HOT OIL HEATER
				42.005	CONDENSATE TANKS
				16.110	TURBINES 9,443-HP SIEMENS SGT-200-2S
				50.002	AMINE UNITS - FLASH TANK
BUFFALO CREEK PROCESSING PLANT	OK-0148	USA	09/12/2012 ACT	17.130	Large Internal Combustion Engines (>500 hp)
				17.130	Large Internal Combustion Engines (>500 hp)
				42.004	Truck Loading (Petroleum Marketing)
				42.005	Condensate Tanks (Petroleum Storage-Fixed Roof Tanks)
				16.110	Small Combustion Turbines (
				50.002	Fugitive Equipment Leaks (Natural Gas Plant)
				50.999	Amine Unit / Sweetening Unit
				13.310	Commercial/Institutional Boilers (
				50.002	Blowdowns and Venting (Natural Gas Plant)
INDIANA GASIFICATION, LLC	IN-0166	USA	06/27/2012 ACT	90.011	INCOMING SOLID FEEDSTOCK MATERIAL HANDLING SYSTEM - BARGE UNLOADING TO HOPPER TRANSFER POINT
				64.003	ZLD INERT GAS VENT
				90.011	BARGE UNLOADING FROM THE HOPPER TO THE BELT AND BARGE CONVEYOR TRANSFER POINTS
				90.011	RAIL HOPPERS UNLOADING TO THE CONVEYOR BELTS AND RAIL CONVEYOR BELT TO THE STACKER
				90.011	STACKER BELTS TO THE RADIAL STACKER
				90.011	TRANSFER SYSTEMS CONSISTING OF HOPPERS AND CONVEYOR BELTS TRANSFERRING FEED STOCK FROM THE PILES TO CLASSIFICATION TOWERS; CLASSIFICATION TOWERS; AND
				90.011	TWO (2) RADIAL STACKERS TO THE PILE
				99.190	TWO (2) STORAGE PILES
				99.190	DOZER ACTIVITIES
				90.011	TRUCK/RAIL CONVEYOR TRANSFER TOWER; TRUCK STATIONS UNLOADING TO A TRUCK HOPPER; AND TRUCK HOPPER UNLOADING TO THE CONVEYOR BELTS
				90.011	FOUR (4) ROD MILL EDUCTOR VENTS
				90.010	TWO (2) ASU REGENERATION VENTS
				62.015	TWO (2) WET SULFURIC ACID PLANTS
				99.009	ASU COOLING TOWER
				64.004	SIX (6) SULFURIC ACID TANKS
				90.010	ZLD SPRAY DRYER
				64.002	FUGITIVE LEAKS FROM PIPING
				99.140	FUGITIVE DUST FROM PAVED ROADS
				90.011	FRONT-END LOADER SLAG HANDLING AND VEHICLE DUST ON SLAG PILE
				99.999	ELECTRIC CIRCUIT BREAKER
				90.011	TWO (2) PROCESS AREA SOLID FEEDSTOCK CONVEYING, STORAGE AND FEEDBIN
				17.110	THREE (3) FIREWATER PUMP ENGINES
				17.110	TWO (2) EMERGENCY GENERATORS

				19.600	FIVE (5) GASIFIER PREHEAT BURNERS
				50.006	ACID GAS REMOVAL UNIT VENTS
				50.006	REGENERATIVE THERMAL OXIDIZER (RTO) ON THE ACID GAS REMOVAL UNIT VENTS (AGR)
				11.310	TWO (2) AUXILIARY BOILERS
				19.390	ACID GAS FLARE
				19.390	SYNGAS HYDROCARBON FLARE
				90.011	RAIL UNLOADING TO RAIL HOPPERS
JACKSON COUNTY GAS PLANT	*TX-0663	USA	05/25/2012 ACT	49.999	Loading Rack
				49.999	Blow downs and starter vent openings
				13.310	Heaters
				13.310	8 Inlet Compressors
				13.310	Residue Compressors
				13.310	Heaters
				13.310	Heaters
				13.310	Heaters
				13.310	Amine Units
				13.310	Glycol Dehy Units
				49.999	Total Fugitives
				42.009	Produced Water Tanks
				42.009	Fixed Roof Tanks
ESSAR STEEL MINNESOTA LLC	MN-0085	USA	05/10/2012 ACT	90.031	FURNACE HOOD EXHAUST
				90.031	INDURATING FURNACE
				90.031	FURNACE WASTE GAS
				90.031	OXIDE PELLET STOCKPILE CONVEYOR GALLERY
				90.031	HEARTH LAYER BIN
				90.031	HEARTH LAYER FEED
				90.031	PELLET DISCHARGE
				90.031	PELLET SCREENING AND HANDLING
				90.031	PELLET SCREENINGS TO REGRIND CONVEYORS
				90.031	CARBON BIN FOR MERCURY CONTROL
				90.031	LIME BIN FOR SCRUBBER
				90.031	PRIMARY GRINDING MILL LINE 3
				90.031	GRIZZLY TRANSFER TOWER
				90.031	NON-MAGNETIC COBBER REJECTS TRANSFER TOWER
				90.031	SECONDARY SCREENING CRUSHER/COBBER LINE 1
				90.031	SECONDARY SCREENING CRUSHER/COBBER LINE 2
				90.031	SECONDARY SCREENING CRUSHER/COBBER LINE 3
				90.031	SECONDARY SCREENING CRUSHER/COBBER LINE 4
				90.031	DOZER ACTIVITY AT TAILINGS BASIN
				90.031	GRADING AT TAILINGS BASIN
				90.031	120K TON CONCENTRATE STOCKPILE LOADING
				90.031	120K TON CONCENTRATE STOCKPILE LOADOUT
				90.031	OXIDE PRODUCT LOADOUT TO RAILCARS
CORPUS CHRISTI TERMINAL	*TX-0676	USA	04/10/2012 ACT	49.999	Crude oil and condensate storage and marine loading.
U.S. STEEL CORP - KEETAC	MN-0084	USA	12/06/2011 ACT	90.031	ALTERNATIVE FUELS DRYER
				90.031	ALTERNATIVE FUELS HAMMERMILL #2
				90.031	ALTERNATIVE FUELS HAMMERMILL #1

				90.031	ALTERNATIVE FUELS DRYER HANDLING
				90.031	ALTERNATIVE FUELS UNLOADING
				90.031	ACTIVATED CARBON BIN
				90.031	LIME BIN
				90.031	MILL FEEDER 2
				90.031	MILL FEEDER 1
				90.031	LIMESTONE BIN
				90.031	COAL BIN 2, PHASE III
				90.031	EMERGENCY TRUCK PELLET LOADING
				90.031	EMERGENCY PELLET CONVEYOR TRANSFER, PHASE III
				90.031	RECLAIM CONVEYOR
				90.031	PELLET SCREENING SYSTEM AND SAMPLER
				90.031	STACKER
				90.031	FINAL TRANSFER CONVEYORS AND LOADOUT CONVEYOR
				90.031	GRATE KILN - TEMPERED PRE-HEAT
				90.031	GRATE KILN - DOWN DRAFT DRYING ZONE 2
				90.031	GRATE KILN - DOWN DRAFT DRYING ZONE 1
				90.031	PELLET PRODUCT CONVEYOR & REJECT DISCHARGE, PHASE III
				90.031	COOLER VIBRATING FEEDER, PHASE III
				90.031	ALTERNATIVE FUELS PREPARED FUEL SILO
				90.031	ALTERNATIVE FUELS INTERMEDIATE DRY FUEL SILO
				90.031	PELLET COOLER - COOLER ZONE C4
				90.031	BENTONITE BIN
				90.031	GRATE DISCHARGE, PHASE III
				90.031	GRATE FEED, PHASE III
SFPP,LP	CA-1226	USA	06/21/2011 ACT	42.002	FUEL CARGO TANK UNLOADING STATION
DIRECT REDUCTION IRON PLANT	LA-0248	USA	01/27/2011 ACT	81.290	DRI-112 - DRI Unit No. 1 Product storage silo Dust Collection
				81.290	DRI-212 - DRI Unit No. 2 Product storage silo Dust Collection
				11.310	DRI-209 - DRI Unit #2 Package Boiler Flue Stack
				11.310	DRI-109 - DRI Unit #1 Package Boiler Flue Stack
				81.290	DRI-207 - DRI Unit No. 2 Furnace Dust Collection
				81.290	DRI-107 - DRI Unit No. 1 Furnace Dust Collection
				81.290	DRI-116 - Screened Product Transfer Dust Collection
				81.290	DRI-115 - Product Screen Dust Collection
				99.190	DRI-118 - DRI Barge Loading Dock
				81.290	DRI-117 - Briquetting Mill
				99.009	DRI-214 - DRI Unit #1 Clean Water Cooling Tower
				99.009	DRI-114 - DRI Unit #1 Clean Water Cooling Tower
				99.009	DRI-213 - DRI Unit #2 Process Water Cooling Tower
				99.009	DRI-113 - DRI Unit #1 Process Water Cooling Tower
				81.900	DRI-204 DRI Unit #1 Iron Oxide Fines Handling
				81.900	DRI-104 DRI Unit #1 Iron Oxide Fines Handling
				81.900	DRI-203 DRI Unit #2 Coating Bin Filter
				81.900	DRI-103 DRI Unit #1 Coating Bin Filter
				81.900	DRI-205 DRI Unit #2 Furnace Feed Conveyor Baghouse
				81.900	DRI-105 DRI Unit #1 Furnace Feed Conveyor Baghouse
				81.900	DRI-202 DRI Unit #2 Iron Oxide Screen Dust Collection
				81.900	DRI-102 DRI Unit #1 Iron Oxide Screen Dust Collection
				81.900	DRI-201 DRI Unit #2 Iron Oxide Day Bins Dust Collection

				81.900	DRI-101 DRI Unit #1 Iron Oxide Day Bins Dust Collection
				81.200	DRI-208 - DRI Unit #2 Reformer Main Flue Stack
				81.200	DRI-108 - DRI Unit #1 Reformer Main Flue Stack
				81.290	DRI-206 - DRI Unit No. 2 Upper Seal Gas Vent
				81.290	DRI-106 - DRI Unit No. 1 Upper Seal Gas Vent
				81.290	DRI-211 - DRI Unit #1 Acid Gas Absorption Vent
				81.290	DRI-111 - DRI Unit #1 Acid Gas Absorption Vent
				19.390	DRI-110 - DRI Unit No. 1 Hot Flare
				19.390	DRI-210 - DRI Unit No. 1 Hot Flare
LANGLEY GULCH POWER PLANT	ID-0018	USA	06/25/2010 ACT	15.210	COMBUSTION TURBINE, COMBINED CYCLE W/ DUCT BURNER
				17.110	EMERGENCY GENERATOR ENGINE
				99.999	BULK CHEMICAL STORAGE SILO LOADING (6)
				99.009	COOLING TOWER
				17.210	FIRE PUMP ENGINE
FLOPAM INC.	LA-0240	USA	06/14/2010 ACT	69.999	Equipment Leaks (Fugitives)
				69.999	Storage Tanks
				69.999	ATBS Plant - Silos, Hoppers, Bagging Operations
				99.150	Roadway Fugitives
				13.310	Boilers
				69.999	Powder Plant Packaging/Loading Areas
				19.200	Thermal Oxidizers
				69.999	Powder Plant - Process Sources
				69.999	Acrylamide Storage and Handling
				69.999	Acrylamide Day Tanks, Acrylic Acid Tanks
				69.999	Vapor Balanced Storage Tanks
				69.999	DADMAC/CM/ADAM/ATBS Plants
				69.999	Specialty Products and PolyDADMAC Plants Reactors
				69.999	Pressurized Tanks
				69.999	Polyamine and Emulsion Plant Tanks & Reactors
				69.999	Emulsion Plant Dissolution Tanks & Reactors
				69.999	Solvent Cold Cleaners
NUCOR STEEL LOUISIANA	LA-0239	USA	05/24/2010 ACT	81.290	SLG-206 - Blast Furnace 2 Slag Pit 3
				81.190	COK-100 - Coke Ovens Coal Handling, Crushing, and Compacting
				81.190	COK-104 - Coke Battery 1 Coke Handling
				81.190	COK-204 - Coke Battery 2 Coke Handling
				81.115	COK-101 - Coke Battery 1 Coal Charging
				81.115	COK-201 - Coke Battery 2 Coal Charging
				81.111	COK-102 - Coke Battery 1 Coke Pushing
				81.290	SIN-103 - Coke and Petcoke Crushing Dedusting Baghouse Vent
				81.290	SIN-105 - Sinter FGD Lime Silo Unloading
				81.290	SIN-106 - Sinter FGD Waste Loading
				81.290	PIG-101 - Pig Iron Desulfurization Station Baghouse Vent
				81.290	STC-101 - Stock House 1 Baghouse Vent
				81.230	PIG-102 - Pig Iron Solidification Baghouse Vent
				90.019	COK-112 - Coke Battery 1 FGD Lime Silo Unloading
				90.019	COK-212 - Coke Battery 2 FGD Lime Silo Unloading
				99.190	COK-113 - Coke Battery 1 FGD Waste Loading
				99.190	COK-213 - Coke Battery 2 FGD Waste Loading
				99.190	TRN-101 - Wagon Tipper

99.009	TWR-101 - Blast Furnace Cooling Tower
99.009	TWR-102 - Iron Solidification Cooling Tower
99.009	TWR-103 - Air Separation Plant Cooling Tower
81.290	STC-201 - Stock House 2 Baghouse Vent
99.150	FUG-101 - Unpaved Road Fugitive Dust
81.190	COK-214 - Coke Bin Tower
81.190	COK-215 - Coke Screening
11.390	STV-201-Blast Furnace 2 Hot Blast Stoves Common Stack
81.900	CST-101- Cast House 1 Baghouse Vent
81.900	CST-201 Cast House 2 Baghouse Vent
99.190	DOC-102 - Dock 2 Loading/Unloading Gantry Crane
99.190	DST-101-Blast Furnace 1 Topgas Dust Catcher
99.190	PIL-101 - Coal Storage Piles
99.190	PIL-102 - Iron Ore Pellet Storage Piles
99.190	PIL-103 - Flux Storage Piles
99.190	PIL-104 - Pig Iron Storage Piles
99.190	PIL-105 - Granulated Slag Storage Piles
99.190	PIL-106 - Sinter Storage Piles
99.190	PIL-107 - Coke Breeze Storage Piles
99.190	PIL-108 - Mill Scale Storage Piles
81.290	SIN-102 - Sinter Plant Main Dedusting Baghouse Vent
81.290	SIN-101 - MEROS System Vent Stack
81.290	SLG-401 - SLAG MILL WET SLAG FEED BIN
81.290	SLG-402 - SLAG MILL DRYER STACK
81.290	SLG-403 - SLAG MILL DRYER BAGHOUSE VENT
81.290	SLG-404 - SLAG MILL DRY SLAG FEED BIN BAGHOUSE VENT
81.290	SLG-405 - SLAG MILL CRUSHERS/SCREENERS BAGHOUSE VENT
81.290	SLG-406 - SLAG MILL BUILDING BAGHOUSE VENT
81.290	SLG-407 - SLAG MILL TRANSFER POINTS BAGHOUSE VENT
81.290	SLG-408 - SLAG MILL PRODUCT SILO BAGHOUSE VENT
81.290	SLG-409 - SLAG MILL LOADING COLLECTOR BAGHOUSE VENT
81.190	PCI-101 - PCI Mill Vent
11.390	STV-101-Blast Furnace 1 Hot Blast Stoves Common Stack
81.112	COK-111-Coke Battery 1 Flue Gas Desulfurization Stack
81.112	COK-211-Coke Battery 2 Flue Gas Desulfurization Stack
81.111	COK-202 - Coke Battery 2 Coke Pushing
81.190	COK-103 Coke Battery 1 Coke Quench Tower
81.190	COK-203 - Coke Battery 2 Coke Quench Tower
81.290	SLG-101 - Slag Granulator 1 Granulation Tank 1
81.290	SLG-102 - SLAG GRANULATOR 1 GRANULATION TANK 2
81.290	SLG-201 - SLAG GRANULATOR 2 GRANULATION TANK 1
81.290	SLG-202 - SLAG GRANULATOR 2 GRANULATION TANK 2
81.290	SLG-301 - AIR-COOLED SLAG PROCESSING LOAD BIN
81.290	SLG-302 - AIR-COOLED SLAG PROCESSING PRIMARY CRUSHER
81.290	SLG-303 - AIR-COOLED SLAG PROCESSING PRIMARY SCREENING
81.290	SLG-304 - AIR-COOLED SLAG PROCESSING SECONDARY CRUSHER

				81.290	SLG-305 - AIR-COOLED SLAG PROCESSING SECONDARY SCREEN
				81.290	SLG-306 - AIR-COOLED SLAG PROCESSING STOCKPILES
				81.290	SLG-104 - Blast Furnace 1 Slag Pit 1
				81.290	SLG-105 - Blast Furnace 1 Slag Pit 2
				81.290	SLG-106 - Blast Furnace 1 Slag Pit 3
				81.290	SLG-204 - Blast Furnace 2 Slag Pit 1
				81.290	SLG-205 - Blast Furnace 2 Slag Pit 2
TRANSMONTAIGNE NORFOLK TERMINA	VA-0313	USA	04/22/2010 ACT	42.009	Storage and Loading of Petroleum Products (Total VOC Emissions)
				42.009	Fugitive emissions (valves, flanges, etc.)
				42.009	Truck Loading Fugitive Emissions from Loading Rack LR-1
				42.009	Loading Rack Emissions from Loading Racks LR-1 and LR-2
				42.009	Barge Loading Emissions (BL-1)
				42.006	Storage Tank Breathing, Working, and Floating Roof Landing Losses (including emergency roof landings)
				42.009	Vapor Combustion Units
J.K. SMITH GENERATING STATION	KY-0100	USA	04/09/2010 ACT	90.019	LIMESTONE STORAGE SILOS
				99.140	HAUL ROADS
				99.999	COALING TOWERS
				99.190	LIMESTONE UNLOADING
				90.019	LIME SILO STORAGES
				90.011	COAL STOCKPILE
				90.011	COAL CRUSHING AND SILO STORAGE
				11.110	CIRCULATING FLUIDIZED BED BOILER CFB1 AND CFB2
				99.120	ASH HANDLING
SFPP,LP	CA-1230	USA	03/05/2010 ACT	42.002	internal floating roof-denatured etahnol cargo tank unloading station
ST. CHARLES REFINERY	LA-0213	USA	11/17/2009 ACT	50.009	WASTEWATER COLLECTION & TREATMENT: REFINERY
				50.003	CRU: CHLOROSORB VENT AND DUST COLLECTOR
				50.006	STARTUPS/SHUTDOWNS - SRU
				11.390	BOILERS (94-43 & 94-45)
				50.008	FLARE 1-5 (15-77, 12-81, 2004-5A, 2004-5B & 2005-38)
				99.009	COOLING TOWERS (13-81, 2004-6, 2005-42, 2005-43, 2008-35)
				50.006	SRU THERMAL OXIDIZERS (99-3, 99-4, 2005-39, 2007-4)
				50.003	FCCU REGENERATOR (16-77)
				50.004	PETROLEUM PRODUCT LOADING DOCKS (94-9)
				50.999	COKER NOS. 1 & 2 STEAM VENT (2005-58 & 2005-59)
				50.999	COKE HANDLING (5-83)
				50.007	FUGITIVE EMISSIONS
				50.008	MVR THERMAL OXIDIZER NO. 1 (94-8)
				64.006	WASTEWATER COLLECTION & TREATMENT: ARU
				42.009	TANKS - FOR BENZENE, XYLENE, SULFOLANE, PAREX, INTERMEDIATE
				50.008	ARU FLARE (2008-36)
				11.390	BOILER 401-E (2004-10)
				13.390	HEATERS/REBOILERS
				12.390	HEATERS (2008-1 - 2008-9)
				50.008	MVR THERMAL OXIDIZER NO. 2 (2008-38)
				13.390	HEATERS (94-21 & 94-29)
				13.390	CPF HEATER H-39-03 & H-39-02 (94-28 & 94-30)
				42.005	TANKS - FOR HEAVY MATERIALS

				62.020	TANKS - FOR SPENT CAUSTIC
				50.004	LOADINGS - REFINERY
				64.005	LOADINGS - AROMATIC RECOVERY UNIT
				50.006	VENT GAS WASH TOWER (99-8)
				50.999	PROCESS VENTS - REFINERY (CCEX)
				11.390	BOILERS (2008-10, 2008-11, 2008-40)
				13.390	DHT HEATERS (4-81, 5-81)
				11.390	HEATER F-72-703 (7-81)
				50.008	THERMAL OXIDIZERS (2008-32, 2008-33, 2008-34)
				42.006	TANKS - FOR LIGHT MATERIALS, SOUR WATER, NAPHTHA, RAFFINATE
PLAQUEMINE PVC PLANT	LA-0204	USA	02/27/2009 ACT	99.140	ROAD - FUGITIVE DUST
				63.999	DELIVERY SILOS A-F (P-3 - P-8)
				63.999	H/C CLEANING SILO (P-9)
				63.036	LOADING HOPPERS (P-25, P-26, P-27)
				17.210	SMALL EMERGENCY ENGINES
				17.110	LARGE EMERGENCY ENGINES
				63.999	ANALYZER VENT 2 (M-10)
				12.390	BOILERS A & B (U-1 & U-2)
				12.390	BOILERS C & D (U-3 & U-4)
				13.310	CRACKING FURNACES A-D
				99.009	COOLING TOWER (P-15)
				99.009	VCM COOLING TOWER (M-7)
				99.009	C/A COOLING TOWER (C-4)
				63.036	PVC DRYER SCRUBBERS A & B (P-1 & P-2)
				19.200	GAS THERMAL OXIDIZERS A & B (M-5 & M-6)
SUN COMPANY, INC., TOLEDO REFI	OH-0308	USA	02/23/2009 ACT	50.003	FLUIDIZED CATALYTIC CRACKING UNIT
				11.390	BOILER (2)
				50.006	SULFUR RECOVERY UNIT
				50.008	FLARE, STEAM ASSISTED
				50.009	WASTEWATER STREAMS
				50.007	LEAK DETECTION AND REPAIR (LDAR) PROGRAM
				50.999	COOLING TOWER
				50.004	PROPYLENE-PROPANE LOADING RACK
				50.006	SULFUR RECOVERY UNIT
POWER COUNTY ADVANCED ENERGY C	ID-0017	USA	02/10/2009 ACT	19.600	ASU REGEN HEATER, 0.1 MMBTU/H, SRC13
				19.600	GASIFIER HEATERS (2), 25 MMBTU/H, SRC14 & SRC15
				99.009	ZLDS COOLING TOWER, SRC30
				12.310	250 MMBTU/H PACKAGE BOILER, SRC24
				99.009	COOLING TOWER, SRC22
				19.310	PROCESS FLARE, SRC21
				62.014	NITRIC ACID PLANT TAILGAS, SRC20
				61.012	UREA GRANULATION VENT, SRC19
				64.003	SELEXOL AGR CO2 VENT, SRC17
				19.310	GASIFIER FLARE, SRC16
				64.002	LEAKS - SYNGAS PIPING OR VALVES, CO FUG
				99.190	SLAG HAND, FUG
				90.019	FLUXANT STORAGE, SRCXX
				90.019	FLUXANT TRUCK LDOUT & CONVEYING, FUG
				90.011	COAL/PETCOKE RECLAIM TO ROD MILL, SRC08-SRC12

				90.011	COAL/PETCOKE RAILCAR UNLOADING & STORAGE, SRC01-SRC07
				61.012	AMMONIUM NITRATE NEUTRALIZER VENT, SRC29
				19.310	AMMONIA STORAGE FLARE, SRC27
				17.110	500 KW EMERGENCY GENERATOR, FIRE PUMP, SRC26
				12.300	250 MMBTU/H STEAM SUPERHEATER BOILER, SRC31
				17.110	2 MW EMERGENCY GENERATOR, SRC25
OHIO RIVER CLEAN FUELS, LLC	OH-0317	USA	11/20/2008 ACT	90.011	COAL OR BIOMASS MILLING LINES FILLING VESSELS (10)
				90.010	SLAG DEWATERING SILOS (6)
				90.010	EQUIPMENT LEAKS
				17.110	EMERGENCY GENERATOR
				11.390	BOILER
				99.190	BIOMASS STORAGE PILES
				90.010	GAS FIRED HEATERS (3)
				90.011	COAL AND BIOMASS SILOS (8)
				90.010	COOLING TOWERS
				90.011	COAL AND BIOMASS CONVERYORS/ TRANSFER TOWERS (5)
				90.011	COAL STORAGE PILES
				90.010	SLAG STORAGE PILES
				90.011	COAL AND BIOMASS RECEIVING BUILDING
				90.011	COAL AND BIOMASS CRUSHER HOUSES (2)
				90.010	FISCHER-TROPSCH REACTOR TRAINS (3)
				90.010	GASIFIER (6)
				90.010	F-T PROCESS UNIT AND PRODUCT UPGRADE SYSTEM
				90.010	F-T CATALYST ROTARY DRYER
				90.010	SULFUR RECOVERY PROCESS UNITS (2)
				99.140	ROADWAYS AND PARKING AREAS
				90.010	SYNGAS CLEANUP TRAINS (3)
				90.011	COAL OR BIOMASS DRYING LINES (10)
				90.011	COAL OR BIOMASS MILLING LINES BUNKER (10)
				42.005	FIXED ROOF TANKS (8)
				42.006	INTERNAL FLOATING ROOF TANKS (4)
				17.210	FIRE PUMP ENGINES (2)
				99.120	FLYASH HANDLING SYSTEM (6)
				42.009	LOADING RACK
				11.390	COMBINED CYCLE TURBINE GENERATORS (2)
CHELSEA TERMINAL	MA-0040	USA	08/20/2008 ACT	42.004	Residual Oil Truck Loading Rack
				42.005	Heated Residual Oil Storage Tanks
STERLINGTON COMPRESSOR STATION	LA-0232	USA	06/24/2008 ACT	17.130	COMPRESSOR ENGINE NO. 1
				16.110	COMPRESSOR TURBINE NO. 1
				16.110	COMPRESSOR TURBINE NO. 2
				42.999	TRUCK LOADING OF CONDENSATE
				17.130	EMERGENCY BACKUP GENERATOR
				42.005	CONDENSATE STORAGE TANK
SFPP,LP	CA-1229	USA	06/06/2008 ACT	42.002	internal floating roof-denatured etahnol cargo tank unloading station
NEW STEEL INTERNATIONAL, INC.,	OH-0315	USA	05/06/2008 ACT	13.110	WASTE HEAT BOILERS (6)
				81.290	TUNNEL FURNACE (2)
				81.290	ROTARY HEARTH FURNACE (6)
				81.290	COOLING TOWERS (12)

				81.290	COAL GRINDING (6)
				81.290	IRON ORE GRINDING (6)
				81.290	CONVEYORS, HOPPERS, SCREENS TO ROTARY HEARTH FURNACE
				81.290	HYDROCHLORIC ACID STORAGE TANKS (8)
				81.290	VACUUM DEGAS BOILERS (2)
				81.290	ACID REGENERATION PLANT (2)
				81.210	ELECTRIC ARC FURNACE (2)
				81.220	LADLE METALLURGY FURNACE (4)
				81.290	PICKLE GALVANIZING LINE (2)
				81.290	ANNEALING FURNACE TO PICKLE GALVANIZING LINE (2)
				81.290	PUSH-PULL CONTINUOUS PICKLE LINE (1)
				99.120	DIRECT REDUCED IRON MATERIAL HANDLING
				81.230	CONTINUOUS CASTERS AND SLAG POT DUMPING (2)
				81.290	VACUUM OXYGENT DEGASSER (4)
				99.140	PAVED ROADWAYS AND PARKING AREAS
				99.120	SCRAP, COAL, IRON ORE BARGE UNLOADING
				99.120	COAL AND IRON ORE UNLOADING & CONVEYING TO STORAGE (3)
				99.120	ALLOY, FLUX, CARBON, LIMESTONE, COKE HANDLING (2)
				81.290	TUNDISH PREHEATER (8)
ENID NITROGEN PLANT	OK-0124	USA	05/01/2008 ACT	61.012	UREA GRANULATORS
				99.009	COOLING TOWER
				99.110	SOLIDS HANDLING AND LOADING
NELLIS AIR FORCE BASE	NV-0047	USA	02/26/2008 ACT	13.310	BOILERS/HEATERS - NATURAL GAS-FIRED
				90.003	ASPHALT CONCRETE MANUFACTURING
				15.190	AIRCRAFT ENGINE TESTING
				17.110	LARGE INTERNAL COMBUSTION ENGINES (>500 HP)
				17.210	SMALL INTERNAL COMBUSTION ENGINES (
				90.024	AGGREGATE PLANT
				90.012	CONCRETE BATCH PLANT
				22.100	GROUND WATER AND SOIL REMEDIATION
				99.130	UNPAVED HAUL ROAD IN THE LANDFILL AREA
				49.011	FACILITY-WIDE CONSUMPTION OF ORGANIC CHEMICALS
				17.220	AIRCRAFT ARRESTORS
				42.005	FUEL TANKS/LOADING RACKS/FUEL DISPENSING
				41.013	PAINT BOOTHS - SURFACE COATING
				99.009	COOLING TOWERS
				30.007	WOOD WORKING
				49.008	DEGREASERS
				21.300	MEDICAL WASTE INCINERATOR
				99.150	ACTIVITIES ON THE UNPAVED VACANT LAND
				13.220	BOILERS/HEATERS - DIESEL OIL-FIRED
BIG CAJUN I POWER PLANT	LA-0223	USA	01/08/2008 ACT	90.011	MATERIAL HANDLING - OUTSIDE CONVEYORS
				99.190	EMERGENCY PILE WIND EROSION
				99.140	PAVED ROADS
				90.011	TRANSFER POINTS - BARGE UNLOADER, UNLOADING HOPPER TO CONVEYOR C-1, CONVEYOR C-1 TO CONVEYOR C-2
				90.011	TRANSFER HOUSE 1 - CONVEYOR C-2 TO CONVEYOR C-3 OR C-4

90.019	LIMESTONE STORAGE DOME
90.011	FUEL STORAGE DOME
90.011	FUEL CRUSHER HOUSE
90.011	FUEL SILOS
90.019	LIMESTONE TRANSFER TOWER - CONVEYOR C-9 TO CONVEYOR C-10
90.019	LIMESTONE SILO AND CRUSHER
99.120	ASH SILO
99.120	ASH TRUCK LOADING
90.019	LIME SILO
11.190	CFB BOILER
90.011	TRANSFER POINT - EMERGENCY PILE MATERIAL HANDLING

Previous Page

Appendix E

International Operations Review

VOC recovery in crude oil loading

Facilities to reduce VOC emissions during loading are providing major environmental benefits driven by emissions standards and legislation

GRANT JOHNSON and MIKE DODD
Costain

Volatile organic compounds (VOCs) are a collection of organic compounds displaying similar behaviour in the atmosphere, contributing to the formation of ground-level ozone and including components such as benzene that are directly hazardous to human health.

Emissions of VOCs have reduced significantly over the last 25 years. There has for example been a more than 50% reduction in non-methane VOCs (NMVOCs) in Europe following the adoption of national ceiling limits on emissions (see **Figure 1**).[1] The reduction has been primarily due to improvements in road transport, reducing both evaporative and exhaust emissions, and through legislative measures limiting the use and emissions of solvents in products.

VOC emissions from production and distribution of oil make up a relatively small proportion of overall global VOC emissions, but the local effects can be significant given for example the large volumes of gas displaced in marine loading of tankers, and the presence of benzene and other harmful substances. Vapour emissions control systems have already been installed at many ports and terminals to recover NMVOCs from loading of both crude oil and products such as naphtha and gasoline.[2]

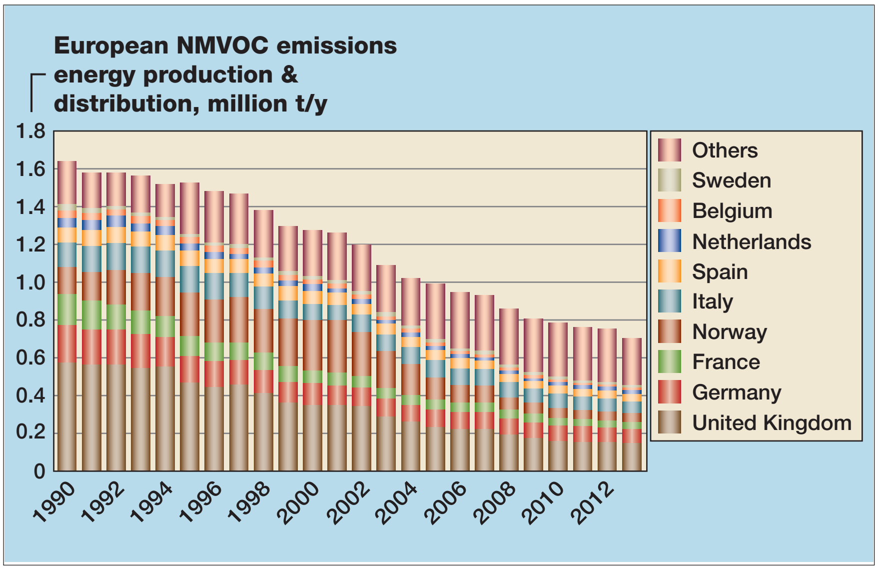


Figure 1 Historic VOC emissions – European Economic Area[1]

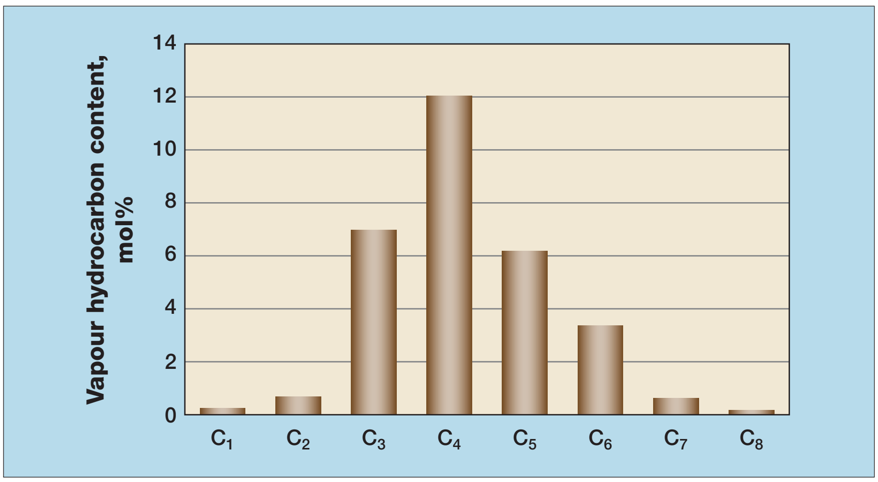


Figure 2 Typical vapour hydrocarbon composition (dry basis)

Vapour evolution and VOC removal requirements

Proprietary simulation tools can be used to calculate the maximum hydrocarbon content (alpha value) of the vapour and also the maximum vapour rate, which depends on the oil composition (including ethane and propane content), loading rate, temperature and vapour pressure at the loading arm.

Where there are multiple loading berths, and a common vapour recovery unit (VRU) is considered, the maximum vapour rate will normally be based on co-incident loading, excluding any very improbable scenarios. A maximum vapour growth rate (the additional vapour volume rate compared with the oil loading rate) of 25% would be typical.

Ship loading will normally be completed in 12-24 hours, and rate of loading will be held steady for

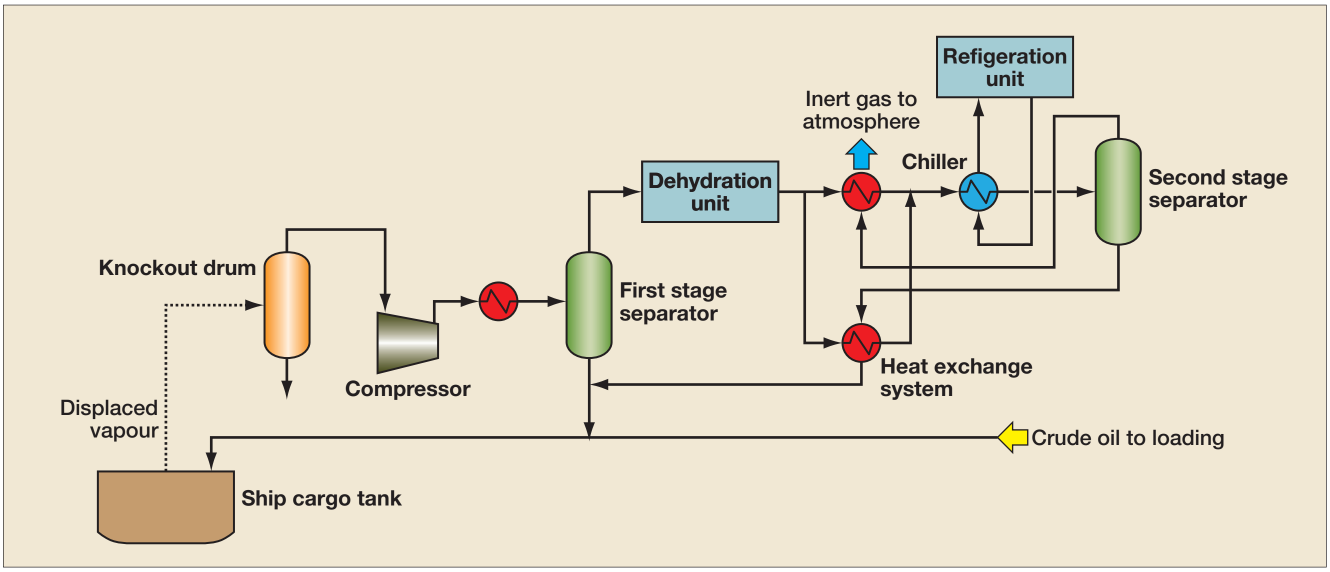


Figure 3 Simplified schematic for condensation (refrigeration) process

the majority of this time. Depending on the ship's operational requirements, start-up and topping off will be at a reduced loading rate of say 20-30% of the normal rate, and for less than one hour. This determines the minimum turndown load on the VRU.

A hydrocarbon content in the displaced vapour of around 30 mol% on a dry basis would be a typical maximum, mainly made up of C_3-C_6 hydrocarbons (see **Figure 2**), of which the benzene content may be greater than 1000 parts per million on a molar basis. Most crude carriers are purged with inert gas generated from the exhaust of the ship's engines, and the inert content of the vapour can therefore contain more than 50 mol% nitrogen, with the balance made up of oxygen, carbon dioxide, carbon monoxide, water vapour, NOx and sulphur dioxide. Terminal regulations will normally limit the hydrogen sulphide, mercaptans and oxygen allowed in the vapour in the ship's tanks at the start of loading. Particulate matter, such as rust, can also be carried with the vapour.

Selection of the technology and design of the vapour collection system and VRU needs to account for the effect of any contaminants present, considering the sensitivity of the process, and impact on equipment and materials of construction.

A typical VRU will have a target recovery of 85-95% of the NMVOC content of the displaced vapour, on top of which there may also be a focus on removing individual components, such as benzene, to a few parts per million depending on local requirements. Legislation in some jurisdictions dictates an absolute limit of NMVOC content in vented vapour.

Close to 1.9 billion tonnes (14 billion barrels) of crude oil were loaded into ships in 2015, displacing around 3 billion cu m of vapour. Each cubic metre can contain up to around 1 litre of valuable recoverable liquid. Although the drivers are primarily environmental, the vapour displaced from loading of a single very large crude carrier (VLCC) carrying 2 million barrels could yield just under 2000 barrels of recoverable oil, with a value at the time of writing of close to $100 000. Depending on the cost of the site specific infrastructure needed for collection and recovery of the vapour, utilisation of the unit, operating costs, and other factors, it is conceivable that payback of around five years could be achieved.

Technology options

Various process technologies are available for reducing VOC emissions, the main ones being:

- Combustion (thermal oxidation)
- Condensation (refrigeration)
- Absorption in crude oil
- Membrane separation
- Absorption in cold liquid (lean oil)
- Pressure swing/vacuum adsorption (carbon vacuum adsorption).

Most solutions in marine loading applications are based on a combination of technologies, increasing the overall recovery and energy efficiency, as described below.

Combustion/thermal oxidation

The hydrocarbon content of the displaced vapour is oxidised to carbon dioxide and water, destroying the harmful components, and also reducing the global warming potential of the gas. Vapour combustion units can handle a wide range of vapour compositions and achieve destruction efficiencies greater than 98%.

Various types of combustion systems are available, ranging from simple enclosed flares to catalytic oxidisers with internal heat recovery. Combustion processes do not recover the valuable VOCs, and they produce carbon dioxide and other combustion products such as carbon monoxide and nitrous and sulphur oxides, emissions of which also need to be controlled to meet applicable environmental regulations and limits. Production of nitrous oxides is dependent on the design of the burner, and also the oxygen concentration at the burner, operating temperature, residence time, and the type of supplementary fuel used. Heat may be recovered from the combustion system if this can be used in the facility.

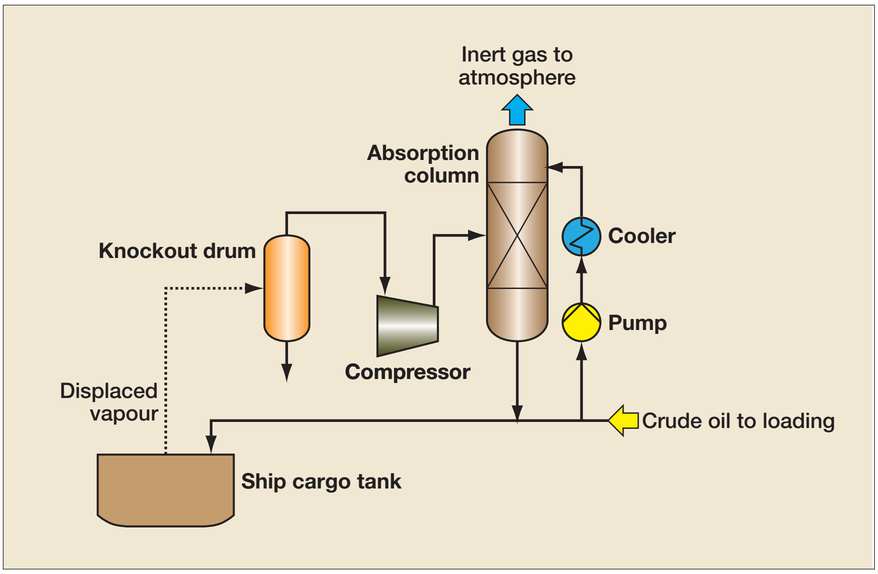


Figure 4 Simplified schematic for crude oil absorption process

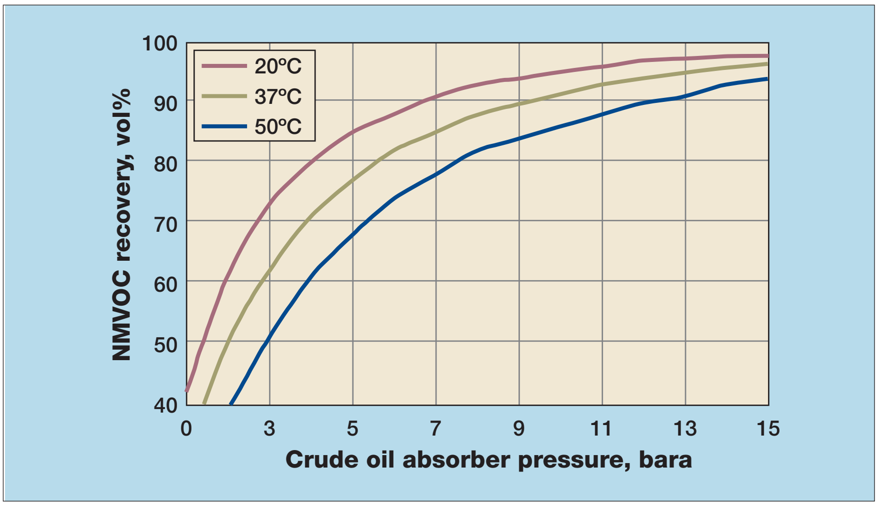


Figure 5 Typical variation in recovery for crude oil absorption vs operating conditions

Combustion processes may be combined with other processes to allow recovery of the majority of the hydrocarbons from the displaced vapour, with only the balance combusted to achieve overall removal efficiencies of over 98%.

Condensation (refrigeration)

If the temperature of the displaced vapour is reduced sufficiently, the VOC content will condense, allowing separation from the vapour. Condensation is normally achieved by compressing the vapour and chilling against evaporating refrigerant (see **Figure 3**). To meet typical emissions targets by condensation alone requires cooling to very low temperatures, and therefore needs a complex refrigeration unit and heat exchange system. To avoid hydrates or freezing, dehydration of the vapour, for example using molecular sieve or injection of methanol, is normally needed prior to chilling.

The complexity and high power requirement means condensation alone is not normally feasible for high throughput plants with tight emissions limits. For smaller facilities, use of evaporating liquid nitrogen can be a feasible option, and advantageous if there is a demand for the utility nitrogen in any case for inerting.

Absorption in crude oil

The displaced vapour is compressed and passed to an absorber column in which it is contacted with crude oil into which the VOC components are absorbed (see **Figure 4**). The crude oil with absorbed VOC is either combined with the crude oil loading the ship, increasing the volume received by the ship, or returned to storage. The inert gas with any VOCs that are not absorbed is vented or undergoes further processing as described below.

The recovery efficiency is highly dependent on conditions in the absorption column (see **Figure 5**) affecting the vapour/liquid equilibrium. The recovery efficiency can be improved by increasing the crude oil flow rate to the column, increasing column pressure or decreasing the crude oil temperature, all of which can however result in a significant increase in both capital and operating cost.

Absorption into crude oil alone cannot economically achieve typical emissions targets and so is commonly combined with other processes.

Membrane separation

Membrane recovery systems rely on the difference in permeability between the VOC and inert constituents of the displaced vapour. The removal efficiency of membrane separation technology alone is insufficient to meet the recovery levels normally targeted, and this technology is typically combined with pre-stage absorption in crude oil. Membrane separation may also be combined with post-combustion of the inert gas to achieve removal efficiencies of over 99%.

The displaced vapour is compressed and passed into an absorption column, where the bulk of the VOC content of the gas is absorbed by contact with crude oil. Gas leaving the top of the absorber column is fed to a membrane unit where the remaining hydrocarbons permeate through the membranes and the inert gas with sufficiently low VOC content is vented to atmosphere (see **Figure 6**).

The necessary driving force across the membrane unit is provided by a vacuum pump, which draws the permeate through the membranes and recycles it back to the upstream absorber. Multi-stage membrane systems are typically required, increasing the compression requirements and complexity of the system.


neles

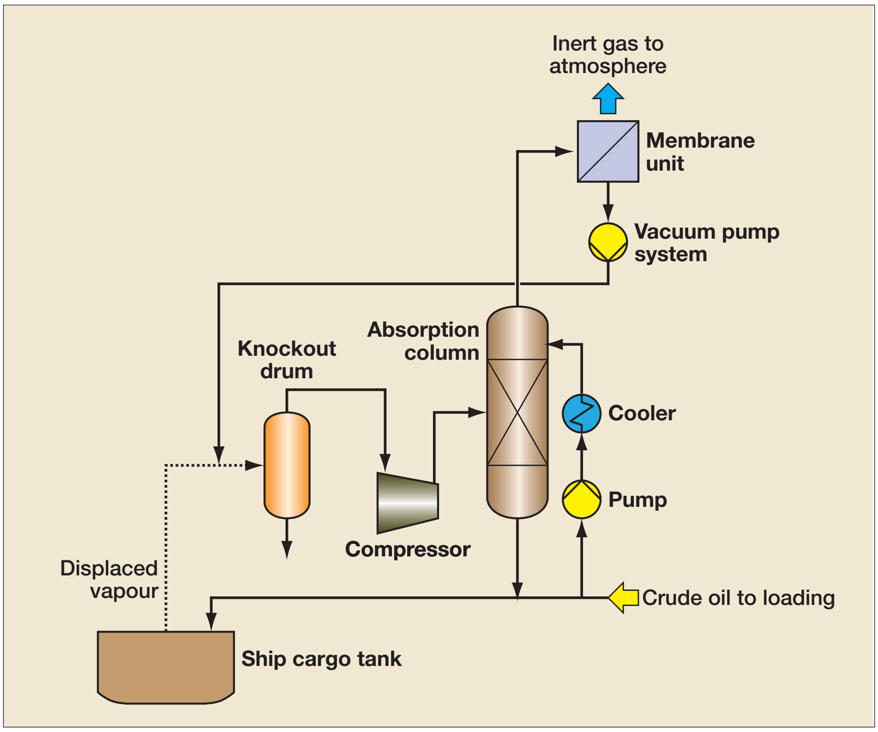


Figure 6 Simplified schematic for pre-absorption with crude oil + membrane separation

Absorption in cold liquid (lean oil)

Two stages of absorption at near atmospheric pressure are used (see **Figure 7**). VOC vapour is first absorbed in a cold lean oil liquid (for instance kerosene). The VOCs are then stripped out of the lean oil using heat in a regeneration system, and are absorbed into crude oil in a second stage absorber.

Absorption based systems are best suited for handling displaced gases with high VOC concentration. At lower concentrations they are less energy efficient than adsorption processes. The lean oil absorption process needs to operate at low temperatures to achieve typical emission targets, and methanol injection is normally required to avoid ice formation.

Lean oil systems have relatively high power and utility requirements, requiring both cooling (normally provided by a dedicated refrigeration unit) and a source of heat for regeneration.

Pressure swing adsorption/carbon vacuum adsorption (CVA)

VOC components can be adsorbed on a bed of activated carbon and high recovery levels are achievable, allowing the vapour leaving the bed to be vented to atmosphere (see **Figure 8**). The adsorbent bed gradually becomes saturated and before breakthrough is reached the online bed is changed over, and the saturated bed is regenerated by creating a vacuum and passing an air purge through the bed to fully regenerate. To achieve continuous operation two or more beds are used.

The effects of certain components, such as mercury, unsaturated hydrocarbons, sulphur dioxide and hydrogen sulphide need to be managed in design and operation. Impurities, such as some sulphur compounds, can be removed on a guard bed installed upstream of the carbon adsorber bed.

Large carbon beds or short cycle times may be required when hydrocarbon concentration in the vapour is high. Also, at high throughputs the bed size is limited by distribution issues and other practical concerns, and multiple beds or multiple trains may be required.

Carbon vacuum adsorption is usually combined with either upstream or downstream absorption of the VOCs in crude oil. Pre-absorption is favoured when the flow rate of the VOCs from the cargo tank is high. Vapours not absorbed in the crude oil are typically fed back to the inlet of the carbon beds.

If it is not possible to provide crude oil for absorption, the VOC rich vapour on regeneration can be compressed and condensed, typically against chilled water, to provide a separate product that can either be further processed, or used as fuel to generate steam or power, although complexity and operating costs are in this case higher.

Vapour recovery at an existing oil terminal

Achieving VOC emissions reduction at existing marine terminals can require complex infrastructure modifications, the cost of which can be several times that of the VRU itself. Avoiding disruption to terminal operations must be a priority in technology selection, engineering design, construction on a live facility, and ultimately in operation, with all interactions between new and existing facilities and operations considered.

At the North Sea Petroleum Terminal, operated by Conoco Phillips in Teesside, UK, Costain designed, constructed and commissioned facilities for VOC recovery, handling 20 000 cu m/h of hydrocarbon rich vapour displaced in the loading of crude oil.

Technology selection for the facility screened all available VOC recovery technologies, and shortlisted three technologies for further evaluation:

- Crude oil pre-absorption + membrane separation
- Carbon vacuum adsorption + crude oil post-absorption
- Two-stage condensation with refrigeration.

The alternative of combustion of the vapour to destroy the VOCs was ruled out, as in this application return on investment could be realised from recovery of the additional crude oil.

The VOC recovery technologies shortlisted had similar order of capital cost, and evaluation by scoring against a set of appropriately weighted criteria was used to arrive at the selected technology. Carbon vacuum adsorption was identified as best available technique, in terms of environmental performance, and the most appropriate technology for the application.

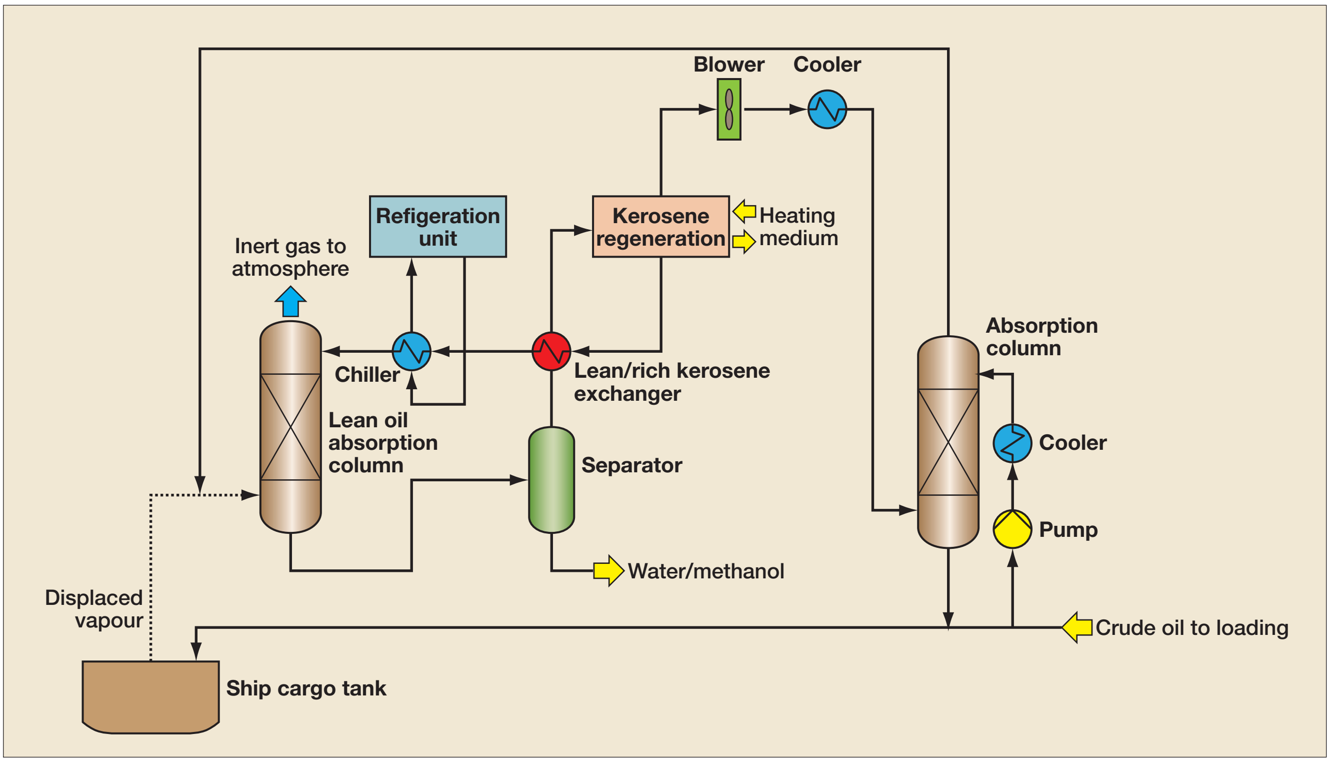


Figure 7 Simplified schematic for lean oil absorption process

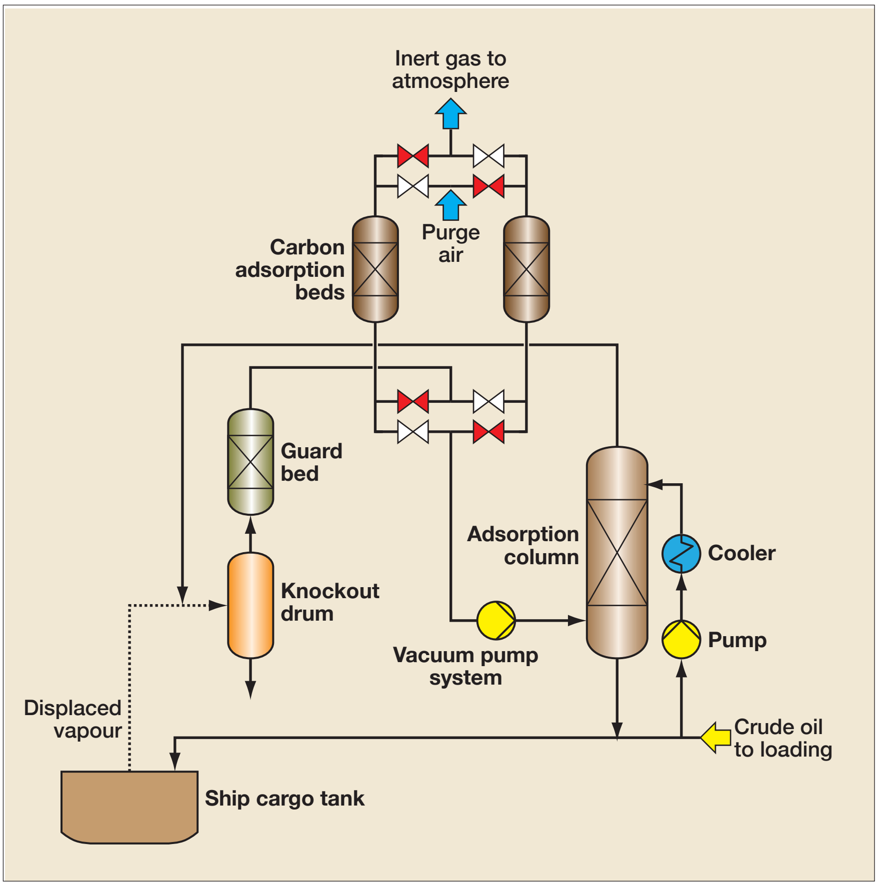


Figure 8 Simplified schematic for carbon vacuum adsorption with crude oil post-absorption

Carbon vacuum adsorption had comparable power requirements and operating cost to the membrane separation process, but was considered to be a less complex and well proven solution at the high capacity required, using two identical trains. The condensation process was identified as having higher operating pressure and power requirements, for compression and refrigeration, than the other options. Performance of the carbon vacuum adsorption process is not sensitive to the VOC content of the vapour, and the unit requires very little time for start-up on demand, with no requirement to pressurise or cool down the system.

The loading berths at the terminal are at a distance of 300-1500 m from the location selected for the VRU. To collect and transport vapour to the VRU, identical facilities were installed on each of the four jetties (see **Figures 9** and **10**), with a vapour unloading arm and a pre-assembled vapour collection module. Each module includes a cartridge filter to remove solids and coalesce any liquid droplets; a detonation arrestor; 2 x 50% vapour blowers; and a vent stack.

The blowers deliver vapour at the required pressure to operate the VRU, and have variable speed and recycle control to ensure a positive suction pressure is maintained, as vacuum conditions could lead to a safety hazard, with the potential for ingress of oxygen and formation of a flammable atmosphere.

On arrival at the two VRU trains, any free liquid condensed from the vapour is knocked out and the vapour is pre-heated before passing through a guard bed to remove impurities such as mercury. The vapour is then passed through the online carbon bed, operating at around 0.25 barg, removing the majority of the heavier hydrocarbons, including benzene (see **Figure 11**). The inert gas, with methane and a small proportion of the heavier hydrocarbons not adsorbed on the carbon, is vented at a safe location. Each carbon bed is taken off line and regenerated several times each hour by reducing the pressure using liquid ring vacuum pumps and booster blowers operating in series and then purging with vent gas to maximise recovery.

Vapour with very high hydrocarbon content from regeneration of the carbon bed is passed to a crude oil absorption column (see **Figure 12**), where it is contacted with a portion of the crude oil send-out stream, into which the majority of the hydrocarbons are absorbed. Any overhead vapour, particularly at the start and end of regeneration, is returned back to the plant inlet.

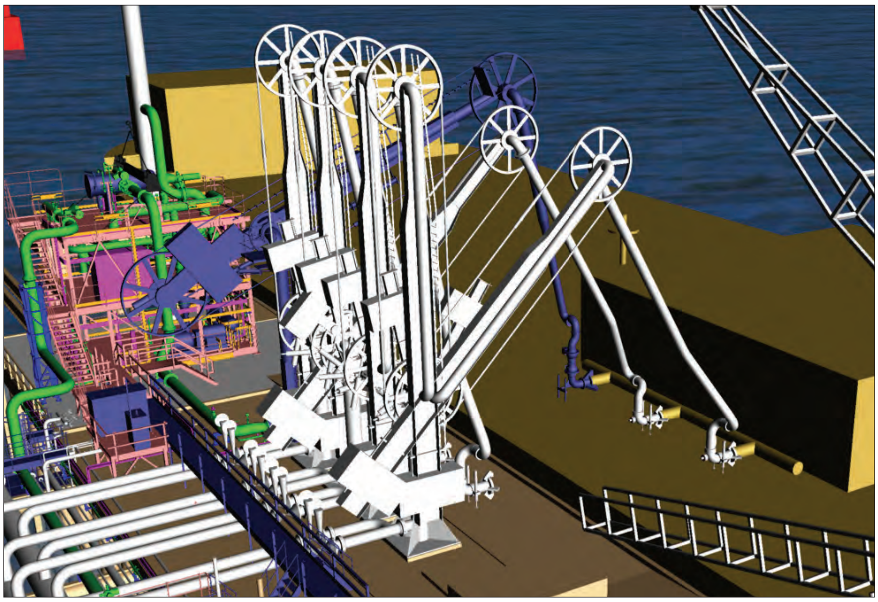


Figure 9 Vapour unloading arm and vapour collection module

Figure 10 Pre-assembled vapour collection module lifted into place on jetty

Figure 11 Vapour recovery unit (two trains) – vacuum carbon adsorption vessels

VOC recovery in offshore loading terminals

Installation of systems for VOC emissions reduction at onshore marine loading terminals has become common, but not all loading is carried out onshore. Vapour emissions from offshore loading at single point mooring (SPM) buoys or fixed structures several kilometres from shore can still affect nearby populations.

Solutions for reduction of VOC emissions at offshore loading terminals are highly dependent on the specifics of the facility, for example whether a fixed structure or a SPM buoy, and the distance from shore. There are typically no facilities for the collection of displaced vapour at offshore loading terminals, the vapour being vented to atmosphere via the ship's mast riser.

Additional challenges in reducing VOC discharges in offshore loading operations are:
• Lack of readily available utilities including power
• Normally unattended facilities
• Motions due to currents, waves

Figure 12 Vapour recovery unit (two trains) – crude oil post-absorption columns

and wind loads for floating facilities
• Cost sensitivity to weight and footprint of the installed equipment
• Need to design for highly saline environment.

Where oil is transported from onshore production facilities to offshore loading terminals through large sub-sea pipelines, there is the option of returning displaced vapour through dedicated sub-sea pipelines to an onshore plant using VRU technology as discussed in the sections above.

This offshore collection/onshore recovery may be preferable to a full offshore solution, unless the following factors impact the feasibility:
• Excessive distance from shore – requiring a very long sub-sea pipeline
• Very large scale loading operations – introducing the need for multiple sub-sea pipelines
• Difficulty in providing offshore compression of the vapour – location, space, power requirements
• Potential for liquid drop out in the vapour return line – and operational impacts such as slugging.

In a recent evaluation for an existing crude oil loading terminal in the Middle East, built on a fixed offshore structure less than 5km from shore, transfer of vapour to an onshore VRU was considered feasible based on a requirement:
• Vapour transfer from the ship's vapour manifold by hose
• Vapour collection modules with filters and blowers close to each loading system
• A common header transferring vapour from each vapour collection module
• A compression module, compressing all vapour from around 0.3 to 3 barg, for example using screw compressors capable of handling vapour with varying molecular weight and range of flow
• A single subsea pipeline
• Equipment for launching and receiving pigs, and separating condensed liquids
• Additional electrical power supply infrastructure.

Evaluating options for vapour control at a facility consisting of several SPM loading buoys, located further offshore, led to the opposite conclusion that transporting the vapour onshore by pipeline was impractical, and a full offshore solution would be required.

In this case, a number of potential locations for the VOC removal unit were conceived, the most feasible identified as location on a barge moored either to the SPM buoy or adjacent to the ship, or on a self-powered vessel that could manoeuvre without assistance from a towing tug. Locating equipment on a modified SPM buoy or on a towing tug was considered infeasible due to a lack of deck space. Locating on a fixed common platform, for example on a metering or control platform associated with the SPM buoys, would require long pipelines from each, and would hence still require equipment close to each SPM buoy to compress and transfer the vapour.

Based on location on a barge moored permanently to the SPM or on a self-powered vessel, the most promising vapour control technologies are those that have:
• Ability to take vapour direct at low pressure from vapour manifold
• Low complexity while achieving required VOC removal
• Low weight and footprint
• Low overall power requirement (or even generate power if this can be used in the process of other systems)
• Low assist gas (typically LPG) requirement

The simplest recovery processes such as absorption in pressurised crude oil have recovery levels limited by oil pressure and temperature, and although this has a relatively compact footprint, compression to an absorber pressure of over 10 barg could be required to achieve VOC recovery of around 90%.

Direct power generation from vapour was also discounted as impractical offshore, with insufficient space available for buffer storage of low pressure vapour, which would allow power generation to be sized based on an average vapour rate. Power generation in offshore locations would therefore either need to be based on peak vapour rate or there would be an excess of fuel at times and the vapour would need to be vented.

Implementation of power generation together with a system for separation and storage of VOC liquids, for example with a refrigerated condensation process or membrane separation process, gets around this problem, and has been implemented at modest scale on board ships where the power can be utilised. It does however introduce the need for more complex processing, including compression and pre-treatment of the vapour.

Direct combustion of the vapour represents the simplest standalone solution with lowest capital cost. Compared with other options it has minimal interaction with loading operations. It has a low maintenance burden and requires minimal operator intervention in normal operation. Combustion also destroys any hydrogen sulphide present in the vapour, avoiding complications of venting gases at levels that may be harmful to operators working locally. Combustion does generate nitrous oxides, but any impact can be assessed relative to the considerable benefits of destroying VOCs. Assist fuel, supplied as liquid, is required at times when the VOC content of the vapour is low.

Other technologies offer a potential return on investment, through recovery of liquids or generation of power, but their additional complexity, footprint and weight count significantly against them. With the relatively low value of the recovered product at the time of writing, technologies that offer a modest payback onshore in addition to their environmental benefits cannot realise such a return in offshore applications where the overall cost of installation, cost of maintenance and so on is much higher.

Conclusion

There are a number of technologies available for VOC recovery from vapour displaced from ships in the marine loading of crude oil. Selection is dependent on the scale of the facility and other site specific factors. Many of the available processes incorporate a crude oil absorption column, allowing the VOC content to be recovered conveniently into the loaded crude oil.

Vapour control at offshore loading facilities presents greater challenges. If it is technically feasible to install equipment to transport the vapour by pipeline to shore, recovery in an onshore plant may be most economical. If this is not practical, for example if loading from SPM buoys a long way from shore, a vapour combustion system installed on a moored barge or self-powered vessel offers a potential solution.

Acknowledgements

The authors thank Costain for support in producing this article, which was first presented at the GPA Europe/GPA GCC Joint Conference in Athens, September 2016.

References

1 ec.europa.eu/eurostat (from European Environment Agency)

2 Moylan J P, Shaw T P, Minimise ship loading emissions, *Hydrocarbon Processing*, Aug 1998.

Grant Johnson is Front End Solutions Manager, responsible for activities in oil & gas, with Costain, Manchester, UK. He holds a master's degree in chemical engineering from the University of Cambridge, UK, and is a Member of the Institution of Chemical Engineers, and a Chartered Engineer in the UK.

Mike Dodd is a Design Safety & Environmental Engineer with Costain, Manchester, UK. He holds a master's degree in chemical engineering from the University of Manchester, UK and is an Associate Member of the IChemE.
Email: mike.dodd@costain.com

Vapor Recovery Technique for Crude Oil Ship Loading —Spray Absorption†

SHIBUYA Yoshiki*1

Abstract:

In petroleum exporting countries, exhaust gas from crude oil tanker through loading operation at offshore terminals is the serious pollutant. A spray absorber, which is not affected by pitching and rolling motions in a floating plant, will be key equipment for the vapor recovery from crude oil ship loading. Because there was no case to apply crude oil sprays for vapor recovery, a series of pilot tests had been conducted to confirm the performance of spray absorber. Crude oil vapor is very complex in nature and it makes the analysis of the pilot test result quite difficult. By focusing on butane, the performance evaluation was easily performed and the possibility to apply the spray absorber was suggested. A simplified model was proposed to trace the phenomena in the absorber, and it was proved that the performance could be simulated by the calculations based on the model.

1. Introduction

Vapor exhausted while loading crude oil has become a serious problem in large-volume transportation of crude oil by tankers. As a large source of volatile organic compound (VOC) emissions, this tanker vapor has become a significant cause of environmental pollution, and it is known that the United States Environmental Protection Agency (EPA) has issued warnings about ground-level ozone originating from VOC pollution[1)]. Particularly in the case of crude oils with high sulfur contents, bad odor caused by tanker vapor has an adverse effect on personnel working at shipping terminals. Moreover, gas also is also a waste of energy resources, as the released VOC includes components which are equivalent to liquefied petroleum gas (LPG) and gasoline. In 2007, JFE Engineering completed construction of the world's largest Tanker Vapor Recovery System (hereinafter, TVR) at the Kiire Terminal of the Nippon Oil Staging Terminal (NOST). This paper describes a demonstration test of the spray absorption which is necessary when developing this technology to oil-producing countries.

2. Tanker Vapor Recovery System

2.1 Treatment Equipment at Kiire Terminal

The process flow diagram of the tanker vapor recovery (TVR) system at the Kiire Terminal is shown in **Fig. 1**.

Tanker vapor is transported to the TVR through vapor collection pipelines. In the TVR plant, first, the vapor is pressurized by a screw compressor, after which it is cooled and introduced into an absorber tower, which is filled with random packing. The crude oil, which is also used as an absorbent, similarly cooled and passed through the absorber tower. The vapor and crude oil are placed in contact in a countercurrent flow in the absorber, and the hydrocarbon component in the vapor is physically absorbed and recovered by the crude oil.

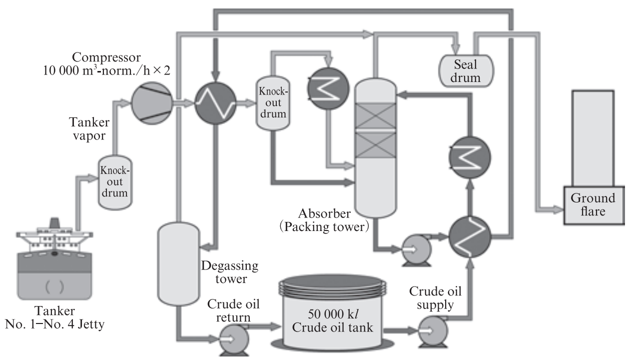


Fig. 1 Process flow of tanker vapor recovery (TVR) at Kiire Terminal, JX Nippon Oil & Energy Staging Terminal Corp.

†Originally published in *JFE GIHO* No. 32 (Aug. 2013), p. 79–86

*1 Principal, Chemical Process, Plant Engineering Dept., Energy Industry Engineering Div., JFE Engineering

In recent years, the role of the Kiire Terminal as a crude oil relay stockpiling tank yard has become increasingly important for Japan. The vapor treated by the TVR System is collected from approximately 300 ships each year, centering on 100 000-ton class tankers. The energy recovered at the Kiire Terminal is equivalent to as much as 10 000 k*l*-crude oil/year.

2.2 Application to Oil-Producing Countries

As described above, while the TVR System is an environmental countermeasure facility, it also produces a significant profit by recovering energy. Application of this outstanding environmental technology in oil-producing countries which ship large volumes of crude oil is expected to contribute to technical progress in those countries and to assist in securing future sources of crude oil. In reality, however, a number of technical hurdles must be overcome in order to apply this technology in oil-producing countries. For example, although oil-producing countries ship large volumes of crude oil by tanker, the loading facilities are generally on offshore platforms or simple buoys such as single point mooring (SPM), and for this reason, it is not possible to secure a site for installation of a TVR plant. Therefore, JFE Engineering, in a tie-up with Universal Shipbuilding Corp. (now Japan Marine United Corp.), conceived a method in which the TVR plant is constructed on a barge, which is then moored alongside tankers, and has proposed construction of marine plants, which can be accomplished at comparatively low cost. **Figure 2** shows a view of the proposed TVR plant on a custom-built vessel.

The problem in this method is the absorber tower. Because the TVR plant is installed on a barge in this type of floating plant, swaying caused by waves is unavoidable. The absorber tower, on the other hand, is an extremely large pressure vessel, with a diameter exceeding 3 m and a height exceeding 20 m. Due to its height, even slight motion at deck level will cause large-amplitude swaying at the top of the tower. Since the absorbent is supplied from the tower top, the inclination of the tower will cause a non-uniform downward flow, and it is also easy to imagine that the inertia of this reciprocal movement will slam the absorbent against the side wall of the tower. As a result, the absorbent will not properly utilize the surface area of the random packing, making it impossible to secure the liquid surface area necessary for absorption in the absorber tower. In recent years, the price of crude oil has remained high for an extended time. In response, producers have aggressively developed deep-water oil fields, and many floating production, storage, and offloading (FPSO) systems are now in operation. However, packed columns like the TVR absorber tower are not used in any of those systems[2)].

Fig. 2 Custom build vessel for offshore tanker vapor recovery (TVR)

As absorbers for use under strong swaying conditions, the spray tower and the cyclone scrubber are conceivable, but because the properties of crude oil differ greatly depending on the oil field, and there are also many unknowns in connection with the vapor, an absorber using the simplest spray method was assumed. In packed column absorber, optimum design of the absorber tower is possible based on data provided by packing manufacturers and the actual values measured at the Kiire Terminal. However, there are no precedents for vapor recovery by a spray tower system which atomizes crude oil, and the data necessary for design are also inadequate. Therefore, during FY 2012, a demonstration test of a spray absorber was carried out with the cooperation of JX Nippon Oil and Energy (NOE) and the Nippon Oil Staging Terminal (NOST).

3. Test Plant

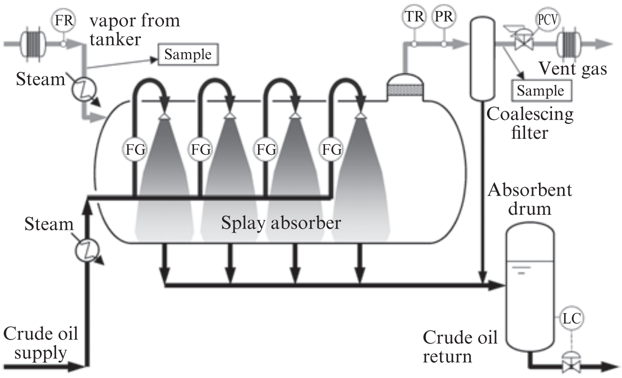
3.1 Outline of Spray Absorber Test Equipment

The spray absorber test was performed using actual vapor-absorbing crude oil and tanker vapor at the Kiire Terminal. An outline of the spray absorber demonstration test equipment is shown in **Fig. 3**.

The spray absorber is a horizontal cylindrical pressure vessel with an inner diameter of 500 mm. The crude oil vapor is passed in the horizontal direction, and the liquid crude oil is spray-atomized downward from above. The spray nozzles comprise a large number of crosscurrent-flow absorbers arranged along the direction of the vapor flow. In the figure, the vapor is introduced from the left side of the absorber and flows to the right at a low flow velocity. The liquid crude oil is atomized by the large number of nozzles from above and placed into direct contact with the vapor. The spray nozzles are

Table 1 Spraying data of the emplyed spray nozzles

Model number	Spray angle			0.05 MPa		0.1 MPa		0.2 MPa (Standared)		0.5 MPa	
	0.05 MPa	0.2 MPa	0.5 MPa	Flow (*l*/min)	d32 (μm)	Flow (*l*/min)	d32 (μm)	Flow (*l*/min)	d32 (μm)	Flow (*l*/min)	d32 (μm)
020	60°	65°	55°	1.06	483	1.46	411	2.00	350	2.91	290
040	60°	65°	55°	2.12	579	2.91	493	4.00	420	5.81	348
060	70°	75°	65°	3.18	655	4.37	558	6.00	475	8.72	393



FR：Flow recorder FG：Flow gauge
TR：Temperature recorder PR：Pressure recorder
PCV：Pressure control valve LC：Level control

Fig. 3 Field test apparatus for spray absorption

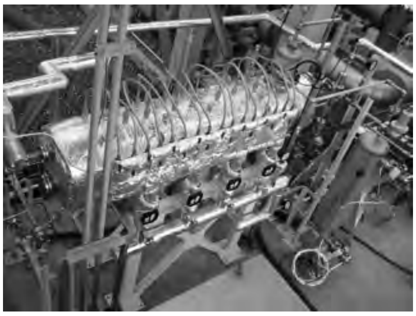


Photo 1 Overview Photo of the Test Spray Absorber

divided into 4 blocks, and the flow rate of each block can be controlled independently. In order to perform tests with a wide range of droplet sizes, mounting seats which enabled easy exchange of the spray nozzles were used. After absorption, the crude oil is discharged from the bottom. The entrained oil mist in the vapor which has passed through the absorber is removed by way of a demister at the top of the discharge side.

As a precaution, a coalescer was installed on the downstream side in order to eliminate the entrained oil mist and prevent scattering to the downstream side. As test conditions, to enable operation at a temperature slightly higher than ambient temperature, heat exchangers were provided to heat both the vapor and the absorbent with steam before introduction into the absorber. A photograph of the test spray absorber is shown in **Photo 1**. For direct monitoring of the condition of atomization, one sight glass and another glass to let in light were provided in the absorber.

3.2 Spray Nozzles

The specification of the spray nozzle used in the test device is shown in **Table 1**. A standard full cone nozzle was selected for the spray nozzles. In case of typical hydraulic spray nozzles, a smaller nozzle has lower spray flow rate, and also makes finer spray droplet. Conversely, when the nozzle size is increased, both the flow rate and the spray droplet size increase, assuming spraying at the same pressure. When the same nozzle size is used, higher pressure gives higher flow rate and smaller droplet size.

3.3 Analysis and Recording

Vapor for use in analysis was sampled at the vapor inlet and exit, as shown in the flow diagram presented previously. The hydrocarbon (HC) content was measured by gas chromatography, and CO_2 content was measured by Orsat analyzer. For other data items such as the flow rate, temperature and pressure, etc., on-line sensor signals were recorded with a data logger.

4. Test Results

4.1 Outline of Results

In case of spray absorbers, process design based on the absorption equivalent to just one theoretical stage is normally conducted. However, sometimes the equilibrium of one theoretical stage might not be achieved due to the atomizing condition or other factors. As the result of this series of tests, the efficiency in HC recovery from tanker vapor was confirmed from the analysis data under a large number of test conditions, as shown in **Fig. 4**. In Fig. 4, the HC concentration of the inlet gas is shown on the *x*-axis, and that of the exit gas is shown on the *y*-axis.

In the absorption equivalent to one theoretical stage, the exit gas HC concentration depends on the inlet gas HC concentration and L/G (Liquid/Gas ratio), where L is liquid flow rate and G is gas flow rate. Under the test conditions shown by the plot points, L/G was expressed by darkness. The graph also shows the results of an equilibrium calculation by a process simulator under a temperature condition of 20°C. In many of the results with low L/G, the exit concentrations are higher than the calculated results, and they indicate the absorption

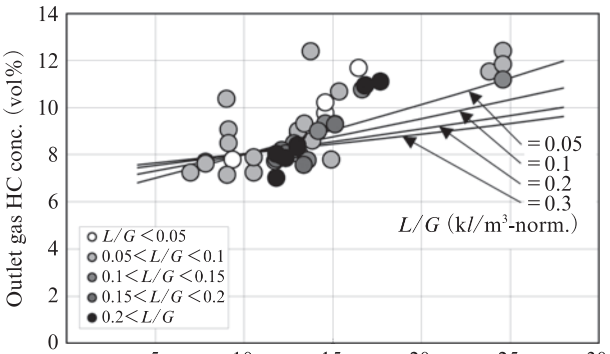


Fig. 4 Overview of the test result

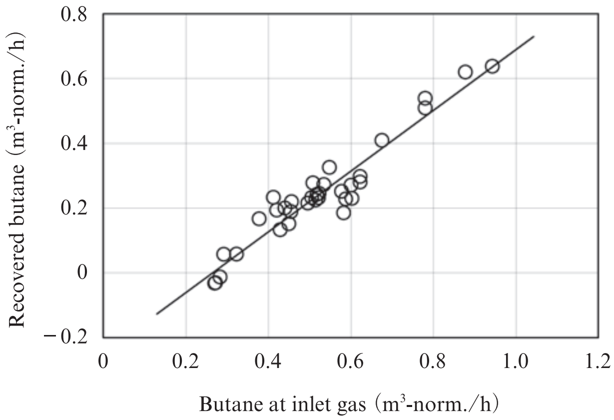


Fig. 5 Absorbed butane flow depends on feed butane flow

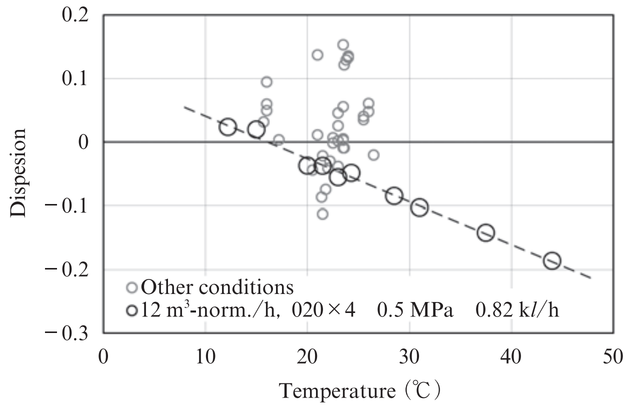


Fig. 6 Temperature effects on the performance

equivalent to one theoretical stage did not be achieved. On the other hand, when L/G is large, the exit concentration was sometimes lower than the calculated value. In such cases, it is supposed that the results were influenced by some factor other than L/G.

4.2 Detailed Confirmation of Results

For various reasons, analysis of absorption performance in a system comprising crude oil and crude oil vapor is extremely difficult. Analysis is difficult, for example, because in such systems, both of liquid and gas are mixtures containing many components, and depending on the case, not only the absorption but also the vaporization from the liquid, may occur due to the higher vapor pressure on the liquid side, etc. In this series of tests, the gas composition at both inlet and exit of the absorber was obtained as the gas chromatography analysis. This analysis was performed focusing on one composition, namely, butane (sum of i-butane and n-butane), which is the component with the largest absorption quantity. In **Fig. 5**, the flow rate of butane in the inlet gas is shown on the x-axis, and that of the recovered butane is shown on the y-axis.

When compared with the graph showing total HC, a quite good correlation can be seen. The primary regression line by the least-squares method is also shown. The relationship between the amount of inlet butane and amount of recovered butane shown here is scattered above and below the regression line as the mean. It is supposed that this expresses larger or smaller amounts of absorption, depending on differences in the test conditions.

Focusing on this deviation from the regression line, we attempted to identify some influential factors. Since temperature is highly influential on the gas-liquid equilibrium, this influence was investigated. A graph of the deviation with temperature on the x-axis is shown in **Fig. 6**.

Because the test conditions other than temperature were same. A sharp correlation can be seen in the tests under various temperature conditions. It is obvious that temperature is the most influential. Moreover, in the tests conducted at ambient temperature, the temperature actually differed in the range from 12°C to 26°C. Therefore, this is considered to be a factor in the scattering of the results.

4.3 Comparison with Balance Calculation

In the simulation described above, the physical properties of the crude oil were modified, because they in the database of the simulator caused significant errors in the simulation. However, to know only butane equilibrium between gas phase and liquid phase of one theoretical stage, it can be a simple calculation according to Raoult's law or Henry's law[3].

Figure 7 shows the operating line of a theoretical stage with an equilibrium line according to Henry's law. The temperature of the liquid side is shown on the x-axis, and the partial pressure of the gas side is shown on the y-axis. Because the temperature and pressure were substantially constant in these tests, all these values were converted to butane content in gas, in order to simplify the comparison with the analysis values. In other words, on the gas side, partial pressure was con-

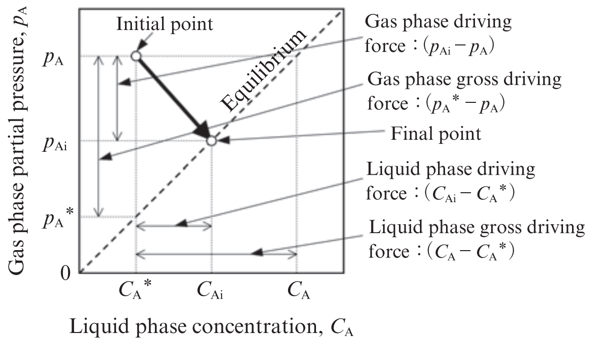


Fig. 7 Equilibrium solubility curve

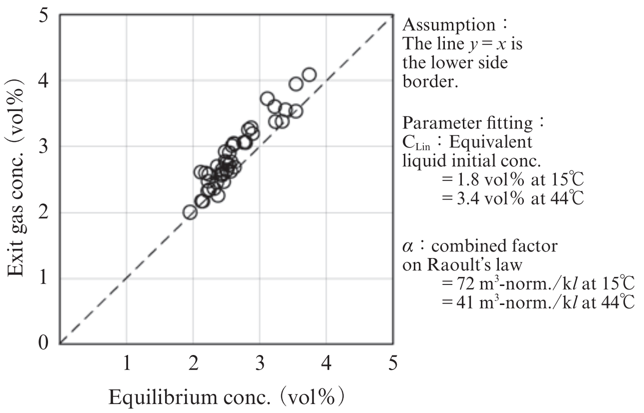


Fig. 8 Calculated equilibrium conc. vs. Analyzed exit conc.

verted to concentration, and the liquid side was converted to the equilibrium concentration of the gas side corresponding to the concentration. α (m^3-norm./kl) was defined as the equilibrium coefficient, and the equilibrium value C_{Geq} was formulated as follows:

$$C_{Geq} = \frac{C_{Gin} + C_{Lin} \times L/G \times \alpha}{L/G \times \alpha + 1} \quad \cdots\cdots (1)$$

In this equation, C_{Lin} and α were obtained by multi-parameter fitting.

In the test results under preferable conditions, the absorption shall almost reach to the calculated equilibrium value. Considering this fact, the parameters were defined so that the envelope of the plot may be in contact with the line where $y = x$. Furthermore, as described previously, because this is a gas-liquid equilibrium, temperature is the most influential factor. Therefore, both C_{Lin} and α were assumed to be linear functions of temperature. The results are shown in **Fig. 8**. The spray conditions and amount of absorption will be discussed in the next chapter.

5. Discussion

5.1 Theory of Spray Absorption

At the microscopic level, mass transfer by direct contact between a gas and a liquid is controlled by the diffusion on the gas side, the gas-liquid interfacial area, and the diffusion in droplets, while at the macroscopic level, the important elements are the gas retention time and liquid holdup. In the case of a packed column, calculation methods are frequently established considering continuation of a steady state in a non-equilibrium condition. On the other hand, when studying direct gas-liquid contact by spraying, although the equipment is simple, the system is difficult, as an unsteady state solution is unavoidable.

Mass transfer at the droplet-gas interface and boundary layers has been studied based on an understanding of the motion of flying droplets and gas flow around the droplets[4], but it is difficult to measure and to estimate the condition of atomized crude oil droplet. Thus, many necessary values remain unknown. Moreover, it is almost impossible to explain the multi-component system of crude oil vapor and liquid crude oil by a strict model. Here, a simplified model is constructed, limiting the focus to the two elements which are indispensable in studying the spray absorption capacity: droplet retention time, and the mass transfer rate limited to butane on the droplet surface, and the calculated and actual values are compared.

5.2 Droplet Retention Time

When a liquid is discharged from a nozzle, it breaks up, forms droplets, and then undergoes continuing deceleration. This deceleration is frequently expressed by an equation of motion in which a sphere is decelerated by the resistance of air[5]. However, since this equation assumes that a spherical particle is not affected by other objects moving in a space where a gas is at rest, it would not be rational to apply this equation to the phenomena which occur during continuous spray atomizing. Although the kinetic energy which is lost to deceleration is received by the gas, if an extremely large number of droplets pass continuously through the gas, the surrounding gas will be accelerated, and within a short time, the velocity of the droplets and the velocity of the gas will become identical. The method of obtaining the velocity at which the kinetic energy comes into balance is much simpler than considering the motions of droplets microscopically, and can also provide a convincing explanation of actual motion.

The flow of gas in the system was modeled as shown in **Fig. 9** by dividing the space into the atomized region and non-atomized region. In the atomized region, the gas gains kinetic energy when the droplets are accelerated, and the gas loses kinetic energy by impact with the wall. In the vicinity of the nozzle, the gas is accelerated when the liquid flow breaks up, and thereafter, the gas continues to accelerate as atomization spreads and gas is drawn into the atomized region. Finally, it is assumed that the whole gas in the cross-sectional of atomized

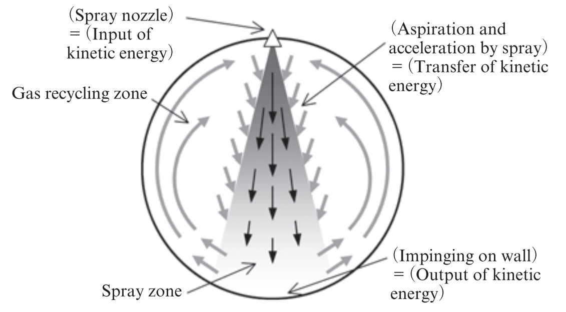


Fig. 9 Model based on the balance of kinetic energy

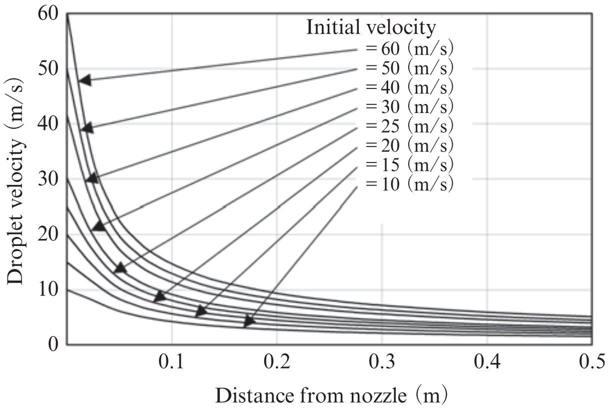


Fig. 10 Calculated droplet velocity distribution

region reaches the same speed as the droplets immediately before impact with the wall, and an energy balance is achieved by this point. Although the droplets which impact on the wall are discharged downstream, the gas returns to the area around the nozzle by way of the non-atomized region.

If the kinetic energy at the outer side of the atomization region is ignored, and it is assumed that the gas reaches the velocity of the droplets at the instant of impact with the wall, the transfer of kinetic energy in the atomization region and the velocity at that time can be calculated in a simple manner. Although the results will differ depending on the spraying flow rate, an example of a calculation with a nozzle and absorber which are actually used is shown in **Fig. 10**.

When the curves in this graph are integrated, the retention time under the majority of the test conditions which were actually used can be estimated as being around 0.1 s. This result is also in good agreement with the result of an analysis of video images taken from the sight glass.

5.3 Simple Model of Spray Absorption

Visual observation confirmed that a gas which gains energy from a spray as described in the previous section is violently stirred. In this system, the retention time of the gas is several minutes, in contrast to the short retention time of the liquid of no more than 0.1 s, as mentioned above. Therefore, the condition is presumed as complete mixing. For this reason, it is assumed that the diffusion velocity of the gas is infinitely large and no concentration distribution exists. Furthermore, in self-washing-type gas absorption using the same liquid which is the gas generation source as the absorbing liquid (in this case, crude oil), the operating condition is generally characterized by an extremely large L/G ratio, and changes in concentration of the liquid are very small. Considering the fact that the droplets are small and the diffusion distance is short, it is assumed that the diffusion velocity in the droplets is also infinitely large and there is no concentration gradient within the droplets. Under these assumptions, it can be thought that mass transfer occurs in a certain entire volume on the gas phase, and in a certain elapsed time following atomization on the liquid phase, considering only the representative concentrations of the two phases. This simplified model is described below.

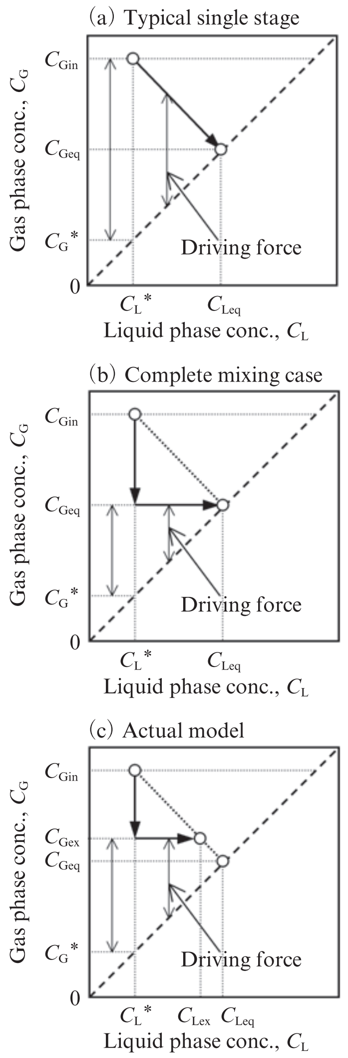


Fig. 11 Model of mass transfer

In **Fig. 11** (a), (b), and (c), a model of mass transfer is considered in a dissolution equilibrium diagram, with the concentration on the gas side C_G on the y-axis and the equivalent gas concentration C_L, in which the gas concentration is converted to the liquid side, on the x-axis. First, Fig. 11 (a) shows the operating line for general absorption, as described above, rewritten as the equivalent gas concentration in this study. This is the theoretical operating line, assuming that the liquid and the gas flow in parallel streams, and there is sufficient time to achieve equilibrium. Since the initial driving force is large on both the gas side and the liquid side, efficiency is good. In contrast to this, if it is assumed that the gas side is completely mixed in the spray absorber, the concentration of the gas side reaches substantially the equilibrium concentration at the instant when the gas enters the system, and the driving force for mass transfer is reduced, as shown in Fig. 11 (b). However, in actuality, equilibrium is not achieved, and the concentration of the gas side becomes constant at an exit concentration which is higher than equilibrium, as shown in Fig. 11 (c). Under this condition, the driving force increases slightly. In any case, only the concentration of butane in droplets can change in this operation. This operation is performed in the short time from discharge of the liquid from the spray nozzle to impact with the wall. From the proportional relationship shown in Fig. 11 (c), the relationship between C_{Gi} and C_{Li} at a certain time is expressed by the following equation.

$$\frac{C_{\mathrm{Gi}}-C_{\mathrm{Geq}}}{C_{\mathrm{Gin}}-C_{\mathrm{Geq}}}=\frac{C_{\mathrm{Leq}}-C_{\mathrm{Li}}}{C_{\mathrm{Leq}}-C_{\mathrm{L}}{}^{*}} \quad \cdots\cdots (2)$$

In applying this model, assuming Henry's law is materialized, as described in the previous chapter, the concentration of butane in the crude oil side exists in a linear relationship with the concentration of butane in gas, which is in equilibrium, and can be handled by conversion. That is, if the subscripts G and L are treated in the same manner, then Eq. (2) can be expanded as follows.

$$C_{\mathrm{Li}}=C_{\mathrm{Geq}}-\frac{\left(C_{\mathrm{Gin}}-C_{\mathrm{Geq}}\right)\times\left(C_{\mathrm{Geq}}-C_{\mathrm{G}}{}^{*}\right)}{C_{\mathrm{Gin}}-C_{\mathrm{Geq}}} \quad \cdots\cdots (3)$$

However, as shown in Fig. 11 (c), the difference between the equilibrium concentration and the final concentration on the gas side acts positively in the driving force.

$$\begin{aligned}\mathrm{DF}&=C_{\mathrm{Gex}}-C_{\mathrm{Li}}\\&=C_{\mathrm{Gex}}-C_{\mathrm{Geq}}+\frac{\left(C_{\mathrm{Gin}}-C_{\mathrm{Geq}}\right)\times\left(C_{\mathrm{Geq}}-C_{\mathrm{G}}{}^{*}\right)}{C_{\mathrm{Gin}}-C_{\mathrm{Geq}}} \quad \cdots\cdots (4)\end{aligned}$$

Where, DF: Driving force (vol%)

In other words, as a model, the liquid side concentration is calculated assuming complete mixing and a uniform concentration on the gas side; however, in the equation, the gas side concentration is a simple term that changes from the initial concentration to the final concentration.

5.4 Mass Transfer Coefficient

In analyzing test results by applying the above-mentioned model, the results of analysis at the gas inlet were used in C_{Gin}, and the results on the exit side were used in C_{Gex}. The $C_{\mathrm{G}}{}^{*}$ used here is the equilibrium gas concentration, C_{Lin}, for the inlet concentration of crude oil obtained by fitting, as described in the previous chapter. In addition to this, the equilibrium concentration C_{Geq} was calculated by using the experimental condition of L/G and the value of α obtained by fitting in the previous chapter, and was assumed as the concrete value of the operating line. The mass transfer in a step time can be calculated by using Eq. (5) with the driving force obtained from these values, and the next concentration can be determined to perform the iterative calculation.

$$N=K\times S\times \mathrm{DF}\times \Delta t \quad \cdots\cdots (5)$$

Where, N: Mass transfer in step time (m^3-norm.)
S: Air-liquid interfacial area (m^2) (Water atomization equivalent)
K: Mass transfer coefficient (m^3-norm./(m$^2\cdot$vol%$\cdot$s))
Δt: Step time used in calculation (s)

The published droplet diameter in water atomization was used as the mean droplet diameter in spray atomization, and the gas-liquid interfacial area (water atomization equivalent) flowing in the system during a step time was calculated on this basis and used in the model calculations. In the calculations, the assumed value of the mass transfer coefficient and the setting value of the step time are necessary, but because a mutually inverse proportional relationship exists between the two, the product $K\cdot\Delta t$ of the mass transfer coefficient and the set step time was used in the calculation formula. Sequential computations beginning from the initial concentration where $C_{\mathrm{Gi}}=C_{\mathrm{Gin}}$ were then performed repeatedly, until the exit concentration where $C_{\mathrm{Gi}}=C_{\mathrm{Gex}}$ was achieved.

5.5 Verification of Model

The calculated results at 6 points in a typical example of a test under various spray conditions, etc. are shown in **Table 2**.

First, **Fig. 12** shows the process by which the retention time for traveling a distance of 500 mm was obtained by performing sequential computations of the droplet velocity using the above-mentioned energy balance under the respective spray conditions.

Besides this process, another sequential computa-

Table 2 Spraying data of the emplyed spray nozzles

Run number	1207B	1118I	1207A	1116E	1116L	1116M
Gas flow rate (m^3-norm./h)	12.46	5.25	11.99	11.08	11.02	5.72
Spray rate (kg/h)	0.35	1.64	0.9	1.66	1.24	1.24
Temperature (˚C)	17.2	24	16.2	23.5	23.6	23.6
Inlet C_4H_{10} (vol%)	2.593	4.694	2.438	4.723	4.67	4.619
Outlet C_4H_{10} vol%	2.163	2.563	1.999	2.631	2.761	2.64
L/G (kg/m^3-norm.)	0.028	0.312	0.075	0.15	0.113	0.217
Equilibrium conc. (vol%)	2.149	2.414	1.957	2.504	2.571	2.285
Nozzle	020	060	020	040	060	060
Spray pressure (MPa)	0.1	0.2	0.5	0.5	0.5	0.5
Initial velocity (m/s)	30.2	41.6	60.4	60.4	60.4	60.4
Droplet diameter (mm)	0.41	0.455	0.28	0.325	0.37	0.37
Spary angle (°)	62	75	55	60	65	65

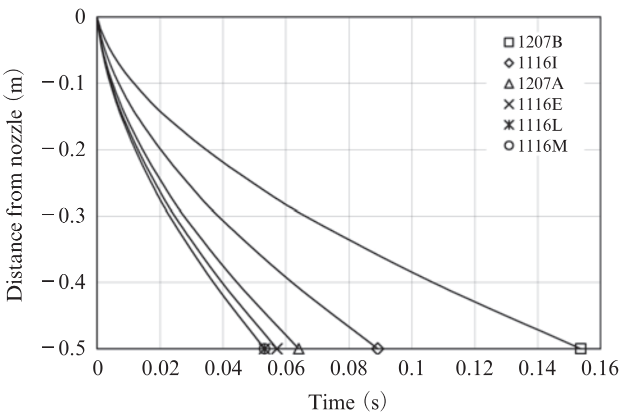


Fig. 12 Retention time calculation for each test

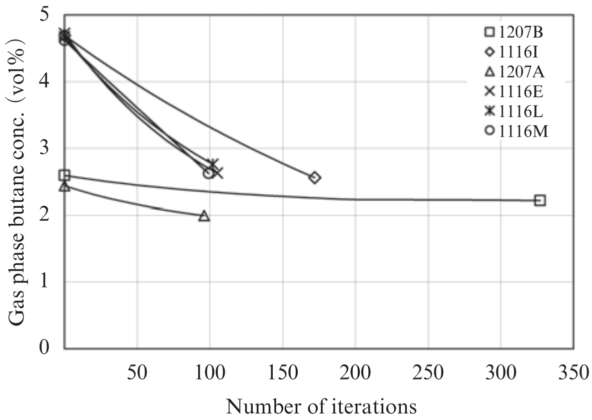


Fig. 13 Iterating calculation of mass transfer for each test

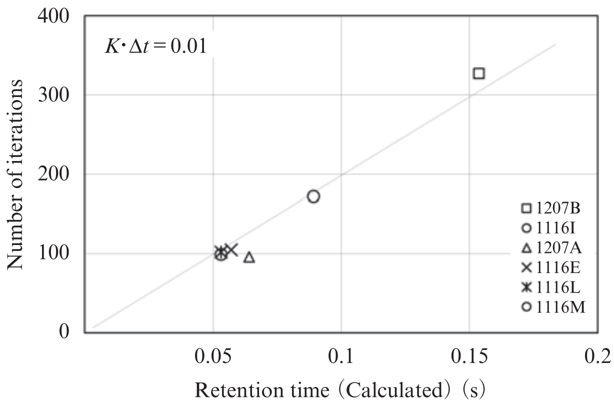


Fig. 14 Correlation between the number of iterations and retention tome

tions of mass transfer, in which the driving force was calculated at a constant gas side concentration, were performed with $K \cdot \Delta t$ set to 0.01. Here, too, the condition in which the gas side concentration was absorbed from the inlet concentration to the exit concentration was plotted in **Fig. 13**.

In the sequential computation of mass transfer, the calculations were performed with many values, including the gas concentration, the flow rates of gas and liquid crude oil as test conditions, the mean droplet diameter in atomization, etc. Although these are data for various conditions, the time when the end-point is achieved showed a relationship similar to the previous droplet retention time. Therefore, the plots of the number of iterations until the exit concentration was achieved for this retention time are shown in **Fig. 14**.

As the calculated results at the 6 points shown in Table 2 are placed on a straight line passing through the origin, it can be understood that a proportional relationship exists between the retention time calculated by the energy balance model and the number of iterations of mass transfer by the complete mixing model. Since both sets of data are judged to have sufficient accuracy, mass transfer coefficients can be calculated from the graph. Moreover, because 300 iterations of the mass transfer calculation is equivalent to a retention time of 0.15 s, the step time Δt of the iterative calculations is 0.000 5 s, and the mass transfer coefficient K is estimated as 0.01/0.000 5 = 20 m^3-norm. ($m^2 \cdot$ vol% $\cdot$ s).

Concerning the atomized droplet diameter, since the manufacturer’s published value for atomization of water is used, the interfacial area equivalent to water atomization is used as the standard for the mass transfer coefficient. This research was successfully completed under this precondition. However, a future investigation will be necessary to determine whether the same evaluation can also be applied in case of different nozzle manufacturers or nozzles with different internal structures.

6. Conclusion

A simple, accurate mass transfer coefficient for the process of recovering hydrocarbons contained in crude oil vapor by spray absorption using crude oil as the absorbent was obtained by the method of (1) analyzing only butane as the object component, (2) obtaining the droplet velocity by a solution based on the kinetic energy balance, and (3) converting the concentration of the crude oil side to the equilibrium concentration for the vapor side, and calculating the mass transfer by a simple model assuming complete mixing on gas phase. This method makes it possible to construct appropriate design standards for the design of large-scale equipment.

Finally, this demonstration test was conducted as part of "Study of Environmental Measures for Crude Oil Shipping Terminals in the Middle Eastern Region (Saudi Arabia)," which is one of Business Development Project for Commercialization in Oil-Producing Countries, and was carried out with the support of a Grant-in-Aid for Refining Technology, Etc. Measures for Oil-Producing Countries for FY 2012 provided by Japan Cooperation Center, Petroleum (JCCP).

References

1) "EPA Proposed Stronger Ground-Level Ozone Standards." Professional Safety. 2007, vol. 52, no. 8, p. 14.
2) Lapidaire, P.; Leeuw, P. "The Effect of Ship Motions on FPSO Topsides Design." Offshore Technology Conference 8079. Houston, USA, 1996.
3) Reid, R. C.; Prausnitz, J. M.; Poling, B.E. "The Properties of Gases and Liquids." 4th ed., McGraw-Hill, 1986.
4) Kugishima, M.; Nakajima, S.; Kunitake, M; Nagaoka, Y. "Development of an Operation Guide for Coke Oven Gas Refinery Process by Use of Absorption Droplet Model." Kawasaki Steel Giho. 1987, vol. 19, no. 2, p. 15.
5) Kajibata, Y.; Miwa, Y; Sakata, Y. "Development of Desulphurization Plants Using Spray Drop Simulation Model." Kagaku Kogaku Ronbunshu. 2006, vol. 32, no. 1, p. 59.